**Options for Meeting Emerging Reliability Needs and Public Policy Initiatives in the Northeast**

The 2011 Conference for the Northeast Chapter of the Energy Bar Association will examine pressures and challenges emerging in the Northeast and whether they will be met through market changes, system planning, new technologies and entrants to the market or other means.

**PROGRAM SCHEDULE**

<table>
<thead>
<tr>
<th>Time</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>TUESDAY, JUNE 7, 2011</td>
<td></td>
</tr>
<tr>
<td>8:00 - 8:30 a.m.</td>
<td>REGISTRATION</td>
</tr>
<tr>
<td>8:30 - 8:45 a.m.</td>
<td>WELCOME &amp; INTRODUCTIONS</td>
</tr>
<tr>
<td></td>
<td>Joseph B. Nelson</td>
</tr>
<tr>
<td></td>
<td>President, Northeast Chapter</td>
</tr>
<tr>
<td></td>
<td>Van Ness Feldman, P.C.</td>
</tr>
<tr>
<td></td>
<td>Derek A. Dyson</td>
</tr>
<tr>
<td></td>
<td>President, Energy Bar Association</td>
</tr>
<tr>
<td></td>
<td>Duncan, Weinberg, Genzer &amp; Pembroke, P.C.</td>
</tr>
<tr>
<td>8:45 - 9:30 a.m.</td>
<td>KEYNOTE ADDRESS</td>
</tr>
<tr>
<td></td>
<td>The Honorable Cheryl A. LaFleur</td>
</tr>
<tr>
<td></td>
<td>Commissioner</td>
</tr>
<tr>
<td></td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>9:30 - 10:30 a.m.</td>
<td>Game Changing or Not: Are there lessons to be learned from the nuclear challenges facing Japan, the gas shortages that faced ERCOT, terrorism-related events, etc?</td>
</tr>
<tr>
<td>10:30 - 10:45 a.m.</td>
<td>BREAK</td>
</tr>
<tr>
<td>10:45 - 11:45 a.m.</td>
<td>Changes in Public Policy. The debate regarding federal and state policy initiatives into transmission planning, demand response, clean energy standards and other governmental initiatives affecting the Northeast Power Markets.</td>
</tr>
<tr>
<td></td>
<td>What paths will Congress, State legislatures and regulators take with respect to policy initiatives on transmission planning, integration of renewables and demand response; and clean energy/climate change measures? How will these initiatives affect resource availability and transmission planning in the region? Can the markets accommodate these measures in their present structures or will further changes be necessary?</td>
</tr>
<tr>
<td></td>
<td>Moderator: Natara G. Feller</td>
</tr>
<tr>
<td></td>
<td>Law Offices of Natara Feller</td>
</tr>
<tr>
<td></td>
<td>Panelists: Andrew Dembia</td>
</tr>
<tr>
<td></td>
<td>Legal Specialist, Office of Chief Counsel</td>
</tr>
<tr>
<td></td>
<td>New Jersey Board of Public Utilities</td>
</tr>
<tr>
<td></td>
<td>Jonathan D. Schneider</td>
</tr>
<tr>
<td></td>
<td>Stinson Morrison Hecker LLP</td>
</tr>
<tr>
<td></td>
<td>T. Michael Twomey</td>
</tr>
<tr>
<td></td>
<td>Vice President, External Affairs</td>
</tr>
<tr>
<td></td>
<td>Entergy Wholesale Commodities</td>
</tr>
<tr>
<td></td>
<td>Mark Babula</td>
</tr>
<tr>
<td></td>
<td>Principal Engineer</td>
</tr>
<tr>
<td></td>
<td>ISO New England</td>
</tr>
<tr>
<td></td>
<td>Ralph Rufrano</td>
</tr>
<tr>
<td></td>
<td>Manager, Compliance Violations Investigations</td>
</tr>
<tr>
<td></td>
<td>Northeast Power Coordinating Council</td>
</tr>
<tr>
<td></td>
<td>Wes Yeomans</td>
</tr>
<tr>
<td></td>
<td>Director of Operations</td>
</tr>
<tr>
<td></td>
<td>New York Independent System Operator</td>
</tr>
</tbody>
</table>
12:00 noon - 1:00 p.m.  LUNCHEON SPEAKER
To Be Announced

1:15 - Challenges for integration of policy goals into the Northeast Regional markets. This panel will address the jurisdictional challenges associated with integrating federal and state policy initiatives into wholesale markets and the challenges of keeping wholesale markets efficient.

Moderator:  Marjorie R. Philips
ISO Services Director
Hess Corporation

Panelists:  Lee Solomon
President
New Jersey, BPU

Debra L. Raggio
Vice President and Assistant General Counsel
GenOn Energy, Inc.

Douglas Egan
Chairman & Chief Executive Officer
Competitive Power Ventures

Joseph Bowring
Market Monitoring Analytics

2:15 - BREAK
2:30 p.m.

2:30 - System planning and operational responses to reliability concerns and policy initiatives.

Moderator:  José Rotger
Manager, ISO & Government Affairs
Energy Security Analysis Inc.

3:45 - Role of Energy Efficiency, Demand Response and New Technologies. Discussions from the utility, investor, provider and planning perspectives on the opportunity and ability of energy efficiency, demand response and new technologies to be effective elements in the wholesale market response to meeting reliability issues and public policy initiatives that will face the Northeast markets in the future.

Moderator:  Lynn Sutcliffe
President & Chief Executive Officer
EnergySolve LLC

Panelists:  Brian Chin
Director, Equity Research
Electric Utilities
Citibank

Judith Judson
Vice President, Asset Management and Market Development
Beacon Power

Roddy Diotalevi
Senior Director
United Illuminating

Khalil Shalabi
Director, Power Resource Planning and Acquisitions
New York Power Authority

4:45 - RECEPTION
6:00 p.m.
Co-hosted by Energy Committee of the New York City Bar Association
KEYNOTE ADDRESS

The Honorable Cheryl A. LaFleur
Commissioner, Federal Energy Regulatory Commission
Game Changing or Not: Are there lessons
To be learned from the nuclear challenges facing Japan, the
Gas shortages that faced ERCOT, terrorism-related events, etc?
The Role of Nuclear Power in the Regional Energy Portfolio

T. Michael Twomey
VP, External Affairs
Entergy Wholesale Commodities
June 7, 2011
Entergy

- Owns and operates five nuclear plants at four sites in New York and New England:
  - Indian Point Energy Center - Units 2 & 3 (Buchanan, NY)
  - James A. FitzPatrick Nuclear Power Plant (Oswego, NY)
  - Vermont Yankee Nuclear Power Station (Vernon, VT)
  - Pilgrim Nuclear Power Station (Plymouth, MA)

- Owns and operates six other nuclear plants in Arkansas, Louisiana, Michigan, and Mississippi.

- Provides management support services to the Cooper Nuclear Station under contract to the Nebraska Public Power District.
Nuclear Power in the U.S.
Energy Cost and Environment

U.S. Electricity Production Costs
1995-2009, In 2009 cents per kilowatt-hour

Production Costs = Operations and Maintenance Costs + Fuel Costs. Production costs do not include indirect costs and are based on FERC Form 1 filings submitted by regulated utilities. Production costs are modeled for utilities that are not regulated.

Source: Ventyx Velocity Suite
Updated: 5/10
Energy Cost and Environment

Comparison of Life-Cycle Emissions
Tons of Carbon Dioxide Equivalent per Gigawatt-Hour

Defense in Depth

- All U.S. nuclear plants are based on a "defense-in-depth" design, which means multiple physical barriers and multiple backup safety systems ensure safe operations even in extreme environments.
- All U.S. nuclear power plants prevent damage to fuel in the reactor or used fuel storage with water as the coolant.
- All Entergy plants have multiple systems for pumping or spraying additional water into the reactor should normal operations be interrupted for any reason.
- Safety-related systems, structures and equipment are designed to withstand severe ground motion and flooding.
- All Entergy plants have multiple systems to provide water to the reactor core in an emergency. Some of these systems are divided into independent subsystems that are powered by multiple redundant power sources. In effect, all Entergy plants have six or more ways to put water into the core in an emergency.
- Entergy nuclear plants have systems and strategies that minimize hydrogen buildup in both primary and secondary containment.
Defense in Depth

- All Entergy Nuclear plants are able to safely shut down and keep the fuel cooled even without electricity from the grid.
- When a plant loses its normal, external power source (from the electric grid), such as at Entergy's Waterford 3 plant during Hurricane Katrina in 2005 or at our New York plants during the 2003 Northeast blackout, multiple systems are available to back up the normal source of electricity. Multiple diesel generators and battery power become available as designed to support the station’s power needs.
- Emergency backup diesel generators at plants start automatically if offsite power is lost. Each plant has at least two diesel generators, with additional diesel generators at some sites.
- Battery banks back up the emergency diesel generators.
- Additional high-capacity generators or special equipment back up each unit’s emergency diesel generators and battery banks.
- If a used fuel pool were to lose water – even in significant quantities – all Entergy Nuclear sites have portable, high-capacity pumps to ensure the pools remain filled.
- Emergency water can be drawn using multiple methods from large water sources that include tanks, large pools of water designed specifically to remove heat from the reactor core, cooling water lakes that frequently cover hundreds of acres, and rivers and other water sources near the plants.
- These systems are constantly tested, challenged or simulated to ensure proper operation when needed.
Defense in Depth

- All U.S. nuclear plants undergo frequent training and drills to ensure the proper function of the redundant safety protocols and emergency plans.

- To prepare for any kind of emergency, such as loss of offsite power, security threats, and hurricane-force winds, our Entergy plant personnel drill on implementation of emergency procedures. Emergency response plans have broad industry involvement, including at least 200 employees at each nuclear power plant. Local, state and NRC officials also have emergency response plans and participate in periodic exercises to demonstrate the integration of each organization’s response.

- In the event that an event goes beyond the design basis plans for a plant, all Entergy plants have Severe Accident Management Guidelines. The guidelines prescribe actions beyond normal emergency operating procedures and address severe challenges to the reactor core of the kind seen in Japan. If such an event were to occur, our operators would exercise procedures to reduce pressure that builds from heat in the reactor while at the same time restoring power sources so that coolant levels can be increased and maintained. Operators are regularly drilled and evaluated on these procedures.
Seismic Profile

Japan

USA
Relicensing

- Commercial nuclear power plants in the U.S. were issued an original 40-year operating license. The 40-year period was not based on technical limitations of plant components.

- According to the NRC, “the license renewal application includes general information and technical information in compliance with 10 CFR Part 54. The license renewal application must contain technical information and evaluations about the different types of plant aging that might be encountered in the specific plant and how the licensee will manage or mitigate those aging effects. This information must be sufficiently detailed to permit the NRC staff to determine whether the effects of aging will be managed such that the plant can be operated during the period of extended operation without undue risk to health and safety of the public. The NRC staff performs a safety review of the information provided in the application, requesting additional information from the applicant as necessary, and draws conclusions about whether the plant can be operated during the period of extended operation without undue risk to health and safety of the public.”
Relicensing

- Applications for plant relicensing for Pilgrim and Indian Point are pending at the NRC.
- The NRC issued a 20-year license renewal for Vermont Yankee on March 21, 2011 (through 2032).
- The NRC issued a 20-year license renewal for FitzPatrick on September 8, 2008 (through 2034).
- 63 U.S. nuclear plants have received renewed operating licenses.
ERDC Event Analysis Process

Ralph Rufrano
NPCC
June 7, 2011
Overview:
  ◦ Background: NERC’s Vision
  ◦ Purpose / Objectives
  ◦ How the EAP Benefits Reliability through the Dissemination of Lessons Learned
On January 26, 2010, Gerry Cauley, President and CEO of NERC announced organizational changes to rebalance NERC’s role as the self-regulatory ERO to deliver improved reliability performance:

- through event and root cause assessment,
- communication of lessons learned,
- tracking of recommendations.

As a result of this new vision, NERC formed its EA&I group to support the reliability of the Bulk Power System (BPS).
Focus on ERO as a “learning” organization
  ◦ Determine / correct event specific causes
  ◦ Disseminate Lesson learned industry-wide to preclude repetition of events
Utilize a bottom up approach
Clarify process, deliverables and roles
Promote reliability by development of a culture of Reliability Excellence
Encourage collaboration
Event Categorization and Analysis

- Cat 1 (low) to Cat 5 (high) reliability significance
- Cat 1 events primarily closed to trend after preparation of Brief Report
- Cat 2 and above
  - Cause analysis
  - Self Assessment expected

All events however are capable of generating lessons learned.
Development /Sharing of Lessons

- Entity experiencing an event with the assistance of their Regional Entity will prepare lesson(s) learned using the template provided in the EAP

- Entity specifics and any other event details that are confidential will be redacted from lessons learned.

- Upon submittal of proposed Lesson learned to NERC:
  - They will be added to a master list, common themes identified and prioritized.
  - Based on priority the draft lessons learned will be presented to the NERC Event Analysis Working Group for review
  - Finalized lessons learned will then be posted to the NERC website for the industry use.
The Benefit

- Analysis of events conducted by those closest to the problem (the entity) and most knowledgeable of their system.

- Throughput Timeliness – specified timelines

- Consistent understanding / execution

- Transparency and dissemination of Lessons preclude repetition of events thereby increasing reliability.
Next Steps

- Phase 2 Field Trial – started 5/2/11
  - 3 month run (nominal)
  - Accrue improvement opportunities (check adjust)
  - Issue another revision by 10/1/11
  - Address CIP related events

- Proposed changes to EAP to NERC BOT by November for proposed inclusion in the Rules of Procedure.
The Roles of the NYISO

Reliable operation of the bulk electricity grid
- Managing the flow of power nearly 11,000 circuit-miles of transmission lines from more than 300 generating units

Administration of open and competitive wholesale electricity markets
- Bringing together buyers and sellers of energy and related products and services

Planning for New York’s energy future
- Assessing needs over a 10-year horizon and evaluating projects proposed to meet those needs

Advancing the technological infrastructure of the electric system
- Developing and deploying information technology and tools to make the grid smarter
Agenda

- 2011 Power Trends
- Gas-Electric Coordination
- Integrating Wind Resources
Power Trends 2011

- Power resource developments over the past decade have contributed to a more reliable system
  - New demand-side programs
  - Additional generating capacity
  - Additional transmission capability
- With planned additions in the near future, the adequacy of power resources is not an imminent concern
- However, the sustained adequacy of resources may be challenged by:
  - The ability to develop replacement generation in the possible event of an Indian Point nuclear station retirement.
  - The cumulative impact of emerging environmental regulations on existing generation
Resource Availability

New York Resource Availability: Summer 2011

- Total Resources Available: 43,068 MW
- Total Resource Requirement: 37,782 MW

- 2,730 MW Total Import Capability
- 2,033 MW Special Case Resources
- 33,285 MW In-State Resources
- 32,712 MW Forecast Peak 2011

5,070 MW Installed Reserve Margin
Generating Capacity

Statewide

New York City

Long Island
Demand Response

Emergency Demand Response and Special Case Resources Programs
(MW by NYISO Zone)
August 2010

Total Registered 2,498 MW
New Generation

80% sited below West-East Interface

Total Nameplate Capacity Added Since 2000
8,650 MW
New Transmission

Transmission Capability Added Since 2000
1,290 MW

Legend
- New
- 765 kV
- 500 kV
- 345 kV
- 230 kV
- 115 kV

- Cross Sound DC Cable
  - 330 MW
- Linden VFT
  - 300 MW
- Neptune DC Cable
  - 660 MW
Gas-Electric Coordination

- Potential for insufficient gas nominations
  - Under-nominations can create gas pipeline pressure problems even on non-peak days
- Firm gas customers receive first priority during peak design day conditions
  - Operational Flow Orders
- Scheduled or forced pipeline outages (rare)
NY Gas-Fired Generation

Gas or Duel-Fuel Generating Capacity

- **Statewide** – 55%
- **Long Island** – 78%
- **New York City** – 95%

- The majority of gas-fired generation stations do not have firm gas wheeling arrangements with their pipeline suppliers
- Daily gas procurement are managed by the generator owners reflected in their bid curves
- Inability to meet electric obligations result in capacity derates
  - Capacity derates can impact generator capacity revenues
Gas Electric Coordination Protocol

- Adopted in response to Order 698
- Contained in NYISO OATT Section 34, Attachment BB
- Applies where a gas system event would likely lead to a loss of firm electric load on bulk power system (as determined by NYISO) or local power system (as determined by local TO).
- Emergency circumstances only – does not apply to generator derated for economic reasons
If a gas system event such as an OFO occurs, NYISO or local TO determines if affected generator is critical to maintaining system load and how many hours of operation is needed to avoid load shed.

TO notifies Power Plant Operator (PP0) of hours and amount of electricity needed from generator.

PPO contacts gas LDC seeking amount of gas needed each hour by the critical generator.

LDC determines whether gas can be made available.

PPO notifies TO of generator availability/unavailability.

TO notifies NYISO of generator rating/derating changes.

New York PSC kept informed (regulates LDC, interest in reliability).

Coordination purposes only – no obligation of LDC to provide gas to non-firm gas customers if gas is unavailable.
Electric & Gas Coordination

- Electric Gas Operating Committee (EGOC)
  - Collection of Northeast Gas Pipeline Companies, gas-fired generators, ISO-NE, NYISO, and PJM
  - Roles include:
    - Seasonal outlooks
    - Infrastructure updates
    - Gas supply studies
Proposed Projects

- Proposed gas-fired projects listed in the NYISO interconnection queue:
  - **Under Construction***:
    - Astoria Energy 2, 617 MW, dual fuel – July 2011
    - Bayonne Energy, 500 MW, dual fuel – May 2012
  - **In Interconnection Queue***:
    - Astoria South Pier, 108 MW, combustion turbine – May 2012
    - CPV Valley, 753 MW, combined cycle – October 2012
    - NRG Berrians GT III, 789 MW, combined cycle – June 2013
    - NRG Berrians GT, 200 MW, combined cycle – June 2013
    - NRG Berrians GT II, 90 MW, combined cycle – June 2013
    - AP Dutchess, 1115 MW, combined cycle – December 2014

*All MW in Winter Ratings*
I-R3: Loss of Generator Gas Supply (New York City)

“The NYS Bulk Power System shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City zone.”

- Con Edison develops minimum oil burn requirements based on loss of gas supply studies at different electric load levels
- Con Edison presents these minimum oil burn requirements to the NYISO Operating Committee for approval
- In some cases the minimum oil burn requirements allow for automatic fuel switching capability
I-R5: Loss of Generator Gas Supply (Long Island)

“The NYS Bulk Power System shall be operated so that the loss of a single gas facility does not result in the uncontrolled loss of electric load within the Long Island zone.”

- Long Island develops minimum oil burn requirements based on loss of gas supply studies at different electric load levels.
- Long Island presents these minimum oil burn requirements to the NYISO Operating Committee for approval.
Windpower in New York

Existing Wind Generation -- 2011
(nameplate capacity) -- 1,348 MW

Proposed Wind Generation
(nameplate capacity) -- 7,039 MW
The NYISO implemented a centralized wind forecasting system in 2008.

Forecasts (Day Ahead and Real-time) are provided to NYISO for all wind plants by AWS Truewind.

Wind generators have access to their individual plant forecasts.

The NYISO uses the wind plant forecasts in its energy market economic dispatch software.
In May 2009, FERC approved NYISO to become the first grid operator to fully integrate wind resources within its economic dispatch process.

Pioneering Wind Dispatch

- Wind Plants
  - Meteorological data (at least every 15 minutes)
  - Real-time forecast every 15 mins

- Forecast data
  - Day-ahead forecast 4AM and 4PM

- Offer $/MW for Real-Time Market
- Basepoint MW in Real-Time Market

- NYISO
  - Current power data (every 15 minutes)
Economic Dispatch of Wind

- Integrating wind units into the Security Constrained Economic Dispatch provides the following benefits:
  - Wind resources indicate their economic willingness to generate in the Real-Time Energy Market (offering in Day Ahead Energy Market remains optional)
  - Identifies and uses the most efficient resources to address reliability [transmission] limitations while minimizing the wind energy limitation and duration
  - Incorporates wind plant dispatch instructions into energy market clearing price (LMP)
  - Minimizes the need for less efficient, out-of-market actions to maintain reliable operations
Planning for More Wind

- In 2009, the NYISO studied the impact up to 8000MW of wind resource integration on system regulation requirements
  - Analyzed the variability of load and wind (net system variability) at specified wind penetration levels and forecasted load levels
  - No significant increase in regulation requirements up to a 3500MW wind penetration level (about 10% of peak load)
  - Increases in the regulation requirement of approximately 10% (25MW) for every 1000MW increase in wind penetration level above 3500MW up to 8000MW (about 23% of peak load).
For Your Information

Power Trends
The NYISO's annual study of energy trends and their impact on New York's bulk electricity grid and the state's competitive wholesale electricity markets.

Conferences & Symposium
In 2011, the NYISO will co-host a symposium, “Energy Synergy: Competition & Innovation,” with ISO-New England. Previous NYISO-sponsored events have addressed smart grid, energy efficiency, wind power, and demand response.

Reports, Reviews & Analysis
The NYISO publishes a wide array of information, including the Annual Report, the Comprehensive System Planning Process documents, the Load & Capacity “Gold Book,” white papers, and other research reports.
The New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating the state’s bulk electricity grid, administering New York’s competitive wholesale electricity markets, conducting comprehensive long-term planning for the state’s electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.

www.nyiso.com
NOTES
Changes in Public Policy:
The Debate Regarding Federal and State Policy Initiatives into Transmission Planning, Demand Response, Clean Energy Standards and Other Governmental Initiatives Affecting the Northeast Power Markets
Table of Contents


5. New Jersey Board of Public Utilities Order Approving Executed SOCAs April 27, 2011.)
48:3-98.1 Electric, gas public utilities energy efficiency and conservation programs, investments, cost recovery; terms defined.

13. a. Notwithstanding the provisions of any other law or rule or regulation to the contrary:

(1) an electric public utility or a gas public utility may provide and invest in energy efficiency and conservation programs in its respective service territory on a regulated basis pursuant to this section, regardless of whether the energy efficiency or conservation program involves facilities on the utility side or customer side of the point of interconnection;

(2) an electric public utility or a gas public utility may invest in Class I renewable energy resources, or offer Class I renewable energy programs on a regulated basis pursuant to this section, regardless of whether the renewable energy resource is located on the utility side or customer side of the point of interconnection; and

(3) the board may provide funding for energy efficiency, conservation, and renewable energy improvements through the societal benefits charge established pursuant to section 12 of P.L.1999, c.23 (C.48:3-60), the retail margin on certain hourly-priced and larger non-residential customers pursuant to the board's continuing regulation of basic generation service pursuant to sections 3 and 9 of P.L.1999, c.23 (C.48:3-51 and 48:3-57), or other monies appropriated for such purposes. The board may also direct electric public utilities and gas public utilities to undertake energy efficiency, conservation, and renewable energy improvements, and shall allow the recovery of program costs and incentive rate treatment pursuant to subsection b. of this section.

b. An electric public utility or a gas public utility seeking cost recovery for any program pursuant to this section shall file a petition with the board to request cost recovery. In determining the recovery by electric public utilities and gas public utilities of program costs for any program implemented pursuant to this section, the board may take into account the potential for job creation from such programs, the effect on competition for such programs, existing market barriers, environmental benefits, and the availability of such programs in the marketplace. Unless the board issues a written order within 180 days after the filing of the petition approving, modifying or denying the requested recovery, the recovery requested by the utility shall be granted effective on the
181st day after the filing without further order by the board. Ratemaking treatment may include placing appropriate technology and program cost investments in the respective utility's rate base, or recovering the utility's technology and program costs through another ratemaking methodology approved by the board, including, but not limited to, the societal benefits charge established pursuant to section 12 of P.L.1999, c.23 (C.48:3-60). All electric public utility and gas public utility investment in energy efficiency and conservation programs or Class I renewable energy programs may be eligible for rate treatment approved by the board, including a return on equity, or other incentives or rate mechanisms that decouple utility revenue from sales of electricity and gas.

c. Within 120 days after the date of enactment of P.L.2007, c.340 (C.26:2C-45 et al.), the board shall issue an order that allows electric public utilities and gas public utilities to offer energy efficiency and conservation programs, to invest in Class I renewable energy resources, and to offer Class I renewable energy programs in their respective service territories on a regulated basis. The board's order shall be reflected in rules and regulations thereafter to be adopted by the board pursuant to the "Administrative Procedure Act," P.L.1968, c.410 (C.52:14B-1 et seq.).

d. As used in this section:

"Class I renewable energy program" means any regulated program approved by the board pursuant to this section for the purpose of facilitating the development of Class I renewable energy in the State.

"Energy efficiency and conservation program" means any regulated program, including customer and community education and outreach, approved by the board pursuant to this section for the purpose of conserving energy or making the use of electricity or natural gas more efficient by New Jersey consumers, whether residential, commercial, industrial, or governmental agencies.

"Program costs" means all reasonable and prudent costs incurred in developing and implementing energy efficiency, conservation, or Class I renewable energy programs approved by the board pursuant to this section. These costs shall include a full return on invested capital and foregone electric and gas distribution fixed cost contributions associated with the implementation of the energy efficiency, conservation, or Class I renewable energy programs until those cost contributions are reflected in base rates following a base rate case if such costs were reasonably and prudently incurred.

L.2007, c.340, s.13.

48:3-98.2 Findings, declarations relative to a long-term capacity agreement pilot program to promote construction of qualified electric generation facilities.

1. The Legislature finds and declares:

a. In 2007, PJM Interconnection, L.L.C., the firm that manages the regional
electric power grid, changed the method of procuring capacity in the wholesale electricity market with the implementation of the reliability pricing model;

b. The PJM reliability pricing model sought to create enhancements to the previously ineffective capacity procurement mechanism which had resulted in projected capacity deficiencies in New Jersey and other areas of the regional power grid. While the reliability pricing model has resulted in significant capacity additions in the form of new demand response resources, new energy efficiency resources, reversals of generation unit retirements, upgrades of existing generating units and certain new peaking facilities available to the region and the State, the reliability pricing model has not resulted in large additions of peaking facilities or any additions of intermediate or base load resources available to the region and the State;

c. The PJM reliability pricing model could, through structural changes, provide necessary incentives, such as the expansion of the "New Entry Price Adjustment" mechanism for the construction of new capacity, including new intermediate and base load plants, by allowing new resources to qualify and receive a guaranteed capacity price for a longer period of time. However, the implementation of similar structural changes was previously denied by FERC and any future implementation is uncertain at this time;

d. To address the lack of incentives under the reliability pricing model, the construction of new, efficient generation must be fostered by State policy that ensures sufficient generation is available to the region, and thus the users in the State in a timely and orderly manner;

e. Due to PJM's lack of authority to order new generation as a means to mitigate local electrical system reliability concerns and solve other issues related to the lack of local generation, and since only PJM has the authority to order transmission system upgrades and expansions to mitigate electrical system reliability concerns caused by transmission system overloads or the lack of local generation being developed, New Jersey is experiencing an electric power capacity deficit and high power prices that may result in the loss of jobs and investment due to the necessity for the upgrade of the transmission system to the west of New Jersey to ensure a reliable supply of electricity and capacity from generators located outside of New Jersey;

f. As a result of a lack of new, efficient electric generation facilities, New Jersey has become more reliant on coal-fired power plants;

g. The PJM State of the Market Report for 2009 by the PJM Independent Market Monitor states that there are over 11,000 megawatts ("MW") of coal-fired units at risk of retirement due to their inability to cover their avoided costs;

h. New Jersey's in-State fleet of electric generation facilities is aging, with over 50 percent of these facilities being more than 30 years old and over 70 percent being more than 20 years old; and
i. Fostering and incentivizing the development of a limited program for new electric generation facilities will help ensure sufficient capacity to stabilize power prices to assist the State's economic development and create opportunities for employment in the energy sector while helping to reduce the cost and volatility of electricity prices in New Jersey.

L.2011, c.9, s.1.

48:3-98.3 Initiation, completion of schedule to support commencement of LCAPP.

3. Notwithstanding any provisions of the "Administrative Procedure Act," P. L. 1968, c.410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate and complete a proceeding in accordance with the schedule set forth in this section to support the commencement of the LCAPP:

a. The board shall initiate and allow such proceeding to be completed no later than 60 days after the effective date of P.L.2011, c.9 (C.48:3-98.2 et al.) to allow for the commencement of the LCAPP. The SOCA or SOCAs resulting from that proceeding shall be awarded and executed no later than 30 days after the approval of the form of the SOCA or SOCAs. The LCAPP shall require selected eligible generators with board approved and executed SOCAs to participate and be accepted as a capacity resource in the base residual auction conducted by PJM.

b. The board shall require that the electric public utilities within the State retain an agent, with the approval of the board, to administer the LCAPP. The agent retained in accordance with this section shall, on behalf of the board, be responsible for:

(1) assisting the board with the establishment of the LCAPP that allows for offering financially-settled SOCA for the purpose of facilitating the development of eligible generators;

(2) prequalifying eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date; and

(3) recommending to the board the selection of winning eligible generators based on the net benefit to ratepayers of each prequalified eligible generator's offer price and term. Eligible generators that can enter commercial operation for delivery year 2015 are to be provided with a weighted preference in addition to the net benefit ratepayer test. Eligible generators shall also indicate the amount of capacity they are offering in the LCAPP.

c. In the proceeding initiated by the board pursuant to this section, the board shall adopt, after notice, the opportunity for comment, and public hearing, an order addressing the following requirements for the LCAPP:
(1) that electric public utilities shall procure 2,000 megawatts of financially-settled SOCAs from eligible generators, which shall include new generation capacity;

(2) that eligible generators participating in the LCAPP shall be required to offer a quantity, in megawatts, offer a price per megawatt-day, and a term of the SOCA to be evaluated by the agent and approved by the board;

(3) that, taking into consideration the agent's recommendation, the board approve the selected eligible generators from among the qualified eligible generators participating in the LCAPP for the award of board-approved long-term financially-settled SOCAs for a term to be determined by the board but not to exceed 15 years;

(4) that the board establish a method and the contract terms for providing for selected eligible generators to receive payments from the electric public utilities for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the SOCP is greater than the RCP for any applicable delivery year and for providing for electric public utilities to receive refunds from the selected eligible generators for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the RCP is greater than the SOCP for any applicable delivery year;

(5) that no single eligible generator or its affiliate may enter into more than 700 megawatts of financially-settled standard offer capacity agreements;

(6) that the board establish criteria associated with the prequalification of eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date;

(7) that the board establish a method for evaluating and comparing the net value to ratepayers of each eligible generator's offer price and term;

(8) that the board establish a method for providing a weighted preference for eligible generators that can enter commercial operation for delivery year 2015;

(9) that eligible generators approved by the board, enter into a SOCA with each of the State's four electric public utilities provided that each electric public utility shall pay or receive refunds pursuant to an annually calculated load-ratio share of the capacity of the SOCA based upon each electric public utility's annual forecasted peak demand as determined by PJM;

(10) that the resulting SOCA shall bind the electric public utilities to the board approved SOCAs with selected eligible generators for the term of the SOCA;

(11) that the selected eligible generators with executed SOCAs shall offer the
capacity, electricity, and ancillary services into the PJM wholesale markets as required by the PJM market rules; and

(12) that selected eligible generators with executed SOCAs shall participate in and clear the annual base residual auction conducted by the PJM as part of its reliability pricing model for each delivery year of the entire term of the agreement.

d. The board shall order the full recovery of all costs associated with the electric public utilities' resulting SOCAs, and the costs of the agent retained pursuant to subsection b. of this section, from ratepayers through a non-bypassable, irrevocable charge.

e. Notwithstanding any other provision of law, each SOCA shall become irrevocable upon the issuance of such order approving a SOCA.

f. Neither the board or any other governmental entity shall have the authority, directly or indirectly, legally or equitably, to rescind, alter, repeal, modify or amend a SOCA or an LCAPP cost rate order, to revalue, re-evaluate, or revise the amount of LCAPP costs, or to determine that the LCAPP charges or the revenues to recover the LCAPP charges for such SOCAs are unjust or unreasonable.

L.2011, c.9, s.3.
By the Board:

On January 28, 2011, Governor Christopher Christie signed into law P.L. 2011, c. 9, amending and supplementing P.L. 1999, c. 23, establishing a Long-term Capacity Agreement Pilot Program (“LCAPP”) to promote the construction of qualified electric generation facilities for the benefit of New Jersey’s electric consumers. This Order initiates a proceeding to implement the actions the New Jersey Board of Public Utilities (“Board” or “BPU”) is required to undertake by P.L. 2011, c. 9., hereinafter referred to as the LCAPP Law.

Background

The LCAPP Law recognizes that PJM Interconnection, L.L.C. (“ PJM”) instituted a Reliability Pricing Model (“RPM”) as a means to improve the previous and ineffective capacity procurement mechanism, ensure that adequate capacity resources will be available, and establish locational capacity price signals in the wholesale electricity market. However, PJM’s current RPM mechanism has resulted in projected capacity deficiencies in New Jersey as well as other areas of the regional power grid. While RPM has resulted in significant capacity additions in the form of new demand response and energy efficiency resources, reversals of generation unit retirements, upgrades of existing generating units and certain new peaking facilities available to the region and the State, it has not resulted in the addition of adequate mid-merit or baseload generation resources in New Jersey or the region.

The Legislature found that while structural changes to RPM could provide those incentives, the implementation of similar structural changes was previously denied by the Federal Energy

1These structural changes could include, for example, expansion of the “New Entry Price Adjustment” mechanism for the construction of new generation capacity, including new mid-merit and baseload generating plants, by allowing new generation resources to qualify and receive a guaranteed capacity price for a period sufficient to attract capital on reasonable cost terms.
Regulatory Commission ("FERC"). Prospective implementation of such structural changes to the RPM is uncertain at this time. Therefore, to address the lack of incentives under RPM to support the addition of mid-merit and/or baseload generation, the Legislature determined that "construction of new, efficient generation must be fostered by State policy that ensures sufficient generation" is constructed on a timely and orderly manner and made available to the region and to users in the State.

The Legislature maintains that PJM lacks authority to order new generation as a means to mitigate local electrical system reliability concerns and solve other issues related to the lack of local generation. Instead, PJM's authority is restricted to ordering transmission system upgrades and expansions to mitigate electrical system reliability concerns caused by transmission system overloads and/or the lack of local generation being developed. Because of this, the Legislature concluded that "New Jersey is experiencing an electric power capacity deficit and high power prices that may result in the loss of jobs and investment" due to a continued need to upgrade the transmission system to the west of New Jersey to ensure that a reliable supply of electricity and capacity flows eastwardly from generators located outside of New Jersey.

Additionally, according to the Legislature, as a result of a lack of new, efficient electric generation facilities, New Jersey has become more reliant on out-dated coal-fired power plants. From a resource adequacy perspective, New Jersey is therefore even more vulnerable to the 1,100 megawatts ("MW") of coal-fired generation at risk of retirement due to the inability of various generation companies to cover their respective going forward cash operating costs plus incremental capital expenditures to ensure environmental compliance in the PJM market.2

The Legislature therefore concluded that creating a limited program to encourage construction of local electric generation facilities while potential enhancements to RPM and other PJM pricing mechanisms are under consideration, will help ensure sufficient capacity to stabilize power prices to promote the State's economic development, create opportunities for employment in the energy sector, and help to reduce the cost and volatility of electricity prices in New Jersey.

The LCAPP Law directs the Board to immediately commence a proceeding to establish a process that will seek offers for financially-settled Standard Offer Capacity Agreements ("SOCA") between the State's electric public utilities ("EDCs") and eligible generators, as defined in the LCAPP Law. The LCAPP Law requires selected eligible generators, with Board approved and executed SOCA, to participate in and be accepted as a capacity resource in PJM's Base Residual Auction ("BRA") conducted each May.

Pursuant to the LCAPP Law, the Board shall require that the State's EDCs retain a single agent, with the approval of the Board, to administer the LCAPP. The agent retained in accordance with the LCAPP law ("LCAPP Agent"), shall, on behalf of the Board, be responsible for:

1) assisting the Board with the establishment of the LCAPP that allows for offering financially-settled SOCA for the purpose of facilitating the development of eligible generators;

2Based upon the PJM State of the Market Report for 2009 issued by the PJM Independent Market Monitor.
(2) pre-qualifying eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date; and

(3) recommending to the Board the selection of winning eligible generators based on the net benefit to ratepayers of each pre-qualified eligible generator's offer price and term. Eligible generators that can enter commercial operation for energy delivery year³ 2015 are to be provided with a weighted preference, in addition to the net benefit ratepayer test. Eligible generators shall also indicate the amount of capacity they are offering in the LCAPP.

Accordingly, to implement the LCAPP Law, the BOARD HEREBY FINDS that it must:

(1) approve a form of SOCA, a financially settled transaction agreement that provides eligible generators with payments from the EDCs for a defined amount of electric capacity for a term specified by the Board not to exceed fifteen (15) years. Pursuant to the LCAPP Law, upon Board approval these payments are a fully non-bypassable irrevocable charge;

(2) approve a method and the contract terms for providing payment to selected eligible generators from the EDCs for the difference between the Standard Offer Capacity Price ("SOCP")⁴ and the Resource Clearing Price ("RCP")⁵ multiplied by the SOCA capacity in the event the SOCP is greater than the RCP for any applicable delivery year, and for providing refunds to the EDCs from the selected eligible generators for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the RCP is greater than the SOCP for any applicable delivery year;

(3) develop criteria associated with the prequalification of eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date while providing a weighted preference based on likelihood of commercial operation for energy delivery year 2015;

(4) develop a method for evaluating and comparing the net value to ratepayers of each eligible generator's offer price and term; and

(5) establish a method for providing a weighted preference for eligible generators that can enter commercial operation for energy delivery year 2015.

---

³Energy Delivery Year is defined as the 12-month period from June 1st through May 31st, numbered according to the calendar year in which the Energy Delivery Year ends.

⁴Standard offer capacity price means the capacity price that is fixed for the term of the SOCA and which is the price to be received by eligible generators under a Board-approved SOCA.

⁵The RCP is the price established for the Locational Deliverability Area ("LDA") by the BRA as conducted by PJM as part of the RPM.
The LCAPP Law requires eligible generators, approved by the Board, to enter into a SOCA with each of the State's four EDCs, provided that each EDC shall pay or receive refunds pursuant to an annually calculated load-ratio share of the capacity of the SOCA based upon each EDC's annual forecasted peak demand as determined by PJM. The resulting SOCAs shall bind the EDCs to the Board-approved SOCAs with selected eligible generators for the term of the SOCA; obligating the selected eligible generators with executed SOCAs to offer the capacity, energy, and ancillary services into the PJM wholesale markets as required by the PJM market rules, and also requiring eligible generators with executed SOCAs to participate in and clear the annual BRA conducted by PJM as part of RPM for each delivery year of the entire term of the SOCA.

Based upon the Legislatively-imposed requirement, the Board's Order approving the recommended SOCAs must be issued on or before March 30, 2011. Furthermore, the LCAPP, once approved by the Board, shall require the State's EDCs to procure up to 2,000 MW of financially-settled SOCAs. Pursuant to the LCAPP Law, the Board shall award the SOCA(s) within thirty (30) days after the Board's approval of the form of the SOCA (i.e. by April 30, 2011).

Therefore, pursuant to the mandates and requirements of the LCAPP Law, the Board HEREBY INITIATES a proceeding and HEREBY DIRECTS Board Staff to notify all affected and/or interested parties by posting notice of this proceeding on the Board’s website. The Board FURTHER DIRECTS the EDCs to post this Order on each of their respective website homepages within two (2) business days of the date of this Order. The Board FURTHER DIRECTS each of the EDCs to electronically supply each of their respective Basic Generation Service suppliers with a copy of this Order within two (2) business of the date of this Order.

In addition, pursuant to N.J.S.A. 48:2-32, the Board HEREBY DESIGNATES President Solomon as the Presiding Officer who is authorized to rule on all motions that may arise during the pendency of this proceeding, as well as establish and modify any schedules that may be set as necessary to secure a just and expeditious determination of the issues, subject to ratification by the Board.

Based upon a request by Board Staff, on February 7, 2011, the EDCs, collectively, submitted to the Board a recommended candidate for the position of LCAPP Agent. Immediately thereafter, on February 7, 2011, the Board's Secretary published a Notice for Solicitation of Comments on the Electric Distribution Public Utilities' recommended LCAPP Agent on the Board's website. Interested parties were requested to electronically submit any comments on the recommended LCAPP Agent by 12:00pm (Eastern Standard Time) on Wednesday, February 9, 2011 for the Board's consideration. No comments were received. The Board, upon reviewing and considering the experience and qualifications of the recommended LCAPP Agent, HEREBY AUTHORIZES the firm of Levitan & Associates, Inc. to be retained by the EDCs as LCAPP Agent, to enable the Board to meet the timelines set forth in the LCAPP Law. The EDCs are HEREBY AUTHORIZED to timely reimburse the LCAPP Agent for its work in connection with this LCAPP proceeding.

The Board HEREBY DIRECTS the LCAPP Agent to immediately commence the work associated with undertaking the pre-qualification process. The LCAPP Agent shall, on behalf of the Board, be responsible for:
(1) assisting the Board with the establishment of the LCAPP that allows for offering financially-settled SOCA's for the purpose of facilitating the development of eligible generators;

(2) pre-qualifying eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of permitting, development, and construction activities necessary to meet the desired in-service date;

(3) evaluating and comparing the net value to ratepayers of each eligible generator's offer price and term;

(4) establishing a method for providing a weighted preference for eligible generators that can enter commercial operation for Energy Delivery Year 2015; and

(5) recommending to the Board the selection of winning eligible generators based on the net benefit to ratepayers of each pre-qualified eligible generator's offer price and term.

Therefore, Board HEREBY ADOPTS the following schedule of milestones:

<table>
<thead>
<tr>
<th>Proposed SOCA Submission</th>
<th>2/14/2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Application Data Sheets Issued by Agent</td>
<td>2/15/2011</td>
</tr>
<tr>
<td>Application Data Sheets Due</td>
<td>2/22/2011</td>
</tr>
<tr>
<td>Initial Comments to Proposed Form of SOCA</td>
<td>2/22/2011</td>
</tr>
<tr>
<td>Reply Comments to Proposed Form of SOCA</td>
<td>2/25/2011</td>
</tr>
<tr>
<td>Final Form of SOCA Issued</td>
<td>3/1/2011</td>
</tr>
<tr>
<td>Final SOCP Bids Due</td>
<td>3/7/2011</td>
</tr>
<tr>
<td>Initial Recommended SOCA Proposals</td>
<td>3/15/2011</td>
</tr>
<tr>
<td>Issue Agent's Report Supporting Selection</td>
<td>3/21/2011</td>
</tr>
<tr>
<td>Public Comments on Agent's Report</td>
<td>3/24/2011</td>
</tr>
<tr>
<td>Board Order on recommended SOCA's</td>
<td>3/30/2011</td>
</tr>
</tbody>
</table>

The Board HEREBY DIRECTS all interested generators to submit an application for a base load or mid-merit generation facility to be considered in the LCAPP proceeding by February 22, 2011, in a form and manner to be specified in the Application Data Sheets posted to the LCAPP web portal at http://www.nj-lcapp.com. The application shall include, at a minimum, all of the information requested in the Application Data Sheets for the LCAPP Agent's review and consideration in the pre-qualification process. Such information will include but shall not be limited to:

a) Identification of project sponsor(s), including contact person, list of officers, partners, and other principal team members, legal status of sponsor(s), corporate affiliations, nature of support agreements, project development experience, other generation assets under development, under construction, and in operation; disclosure of any instance in which the sponsor, its officers, directors, partners, and other principal team members have been convicted of any felony or crime related to the sale or purchase
of power, generating assets, or other energy or services; a financing plan, credit rating of sponsor (and/or guarantor), and recent financial statements.

b) A detailed description of the new generating facility, including but not limited to type of generation technology, location, installed capacity, capacity expected to be cleared in an upcoming BRA, position in the PJM generation queue, status in the PJM interconnection process, estimate of all relevant interconnection costs, status of all necessary permit applications, plant operating characteristics, and projected in-service date. Thermal projects (including fossil fueled and biomass) shall provide fuel type and fuel supply plans. Non-dispatchable projects (e.g., wind, solar, combined heat and power) shall provide expected operating profiles by month and time of day.

c) Environmental attributes associated with the new generation facility, such as brownfield site reuse, water supply and discharge, air emissions, and proximity to sensitive resources.

d) Community benefits associated with the new generating facility, such as construction period and operating period employment, shares of local labor and materials used in construction, land use improvements, evidence of community acceptance, and property taxes or payment-in-lieu-of-taxes.

f) A demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date (eligible generators that can enter commercial operation for energy delivery year 2015 will be provided with a weighted preference, in addition to the net benefit ratepayer test).

g) Certification that construction of the generation facility has not begun as of January 28, 2011 (the effective date of the LCAPP Law).

h) Any other pertinent information the potential generator believes would support the application.

The potential generators and the EDCs shall furnish any additional information requested by the LCAPP Agent in an expeditious manner but in no event, later than three (3) business days after the request for information is made.

The Board HEREBY DIRECTS the EDCs, either collectively or individually, as well as any other interested party, to submit to the Board for its consideration, on or before February 14, 2011, a proposed form of SOCA in a readable electronic format. All proposed forms of SOCA shall be posted on the Board’s website for public review and comment. All comments regarding the proposed form of SOCA are to be submitted on or before February 22, 2011. Reply comments are to be submitted on or before February 25, 2011. On or before March 1, 2011, a final form of SOCA will be posted on the Board’s website.

The Board HEREBY DIRECTS the EDCs, either collectively or individually, as well as any other interested party to submit on or before March 1, 2011, to the Board for its review and
consideration, a method for providing selected eligible generators with the requisite payments from the EDC for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the SOCP is greater than the RCP for any applicable delivery year, and for providing EDCs with refunds from the selected eligible generators for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the RCP is greater than the SOCP for any applicable delivery year. The proposals should also include a methodology for collecting from and refunding to ratepayers the resulting amounts.

The Board HEREBY DIRECTS each of the EDCs to submit to the Board, on or before March 1, 2011, the EDC’s annual forecasted peak demand for Energy Delivery Years 2011, 2012, 2013 and 2014 as determined by PJM.

On or before March 7, 2011, potential generators shall submit firm and binding SOCP offers. The proposed term covering the firm and binding SOCP offers shall not exceed fifteen (15) years. The firm SOCP offer shall reflect in full the terms and conditions in the final form of the SOCA.

The Board HEREBY DIRECTS the LCAPP Agent upon review of the information as identified in this Order, submitted by potential generators, the EDCs and/or any other interested stakeholder, as well as any other information deemed necessary by the LCAPP Agent to perform its duties, to issue a report setting forth a recommendation to the Board of winning eligible generators based upon the criteria set forth in the LCAPP Law and this Order, no later than March 21, 2011. The LCAPP Agent’s report will be posted on the Board’s website subject to public review and comment by any interested stakeholder. Public comments will be due no later than March 24, 2011, unless the LCAPP Agent’s report is posted on the Board’s website prior to March 21, 2011, in which case the deadline for public commentary will advance day for day, weekend days excluded.

In the event the LCAPP Agent elects to reissue the Report supporting the Agent’s basis for the selection of the SOCP offers, the Report shall be reissued no later than March 28, 2011. The Board intends to issue an Order on the recommended SOCAs on March 30, 2011.

The Board HEREBY ORDERS the EDCs to defer any and all reasonably and prudently incurred costs associated with retention of and work performed by the LCAPP Agent, retained by the EDCs in order to assist the Board, for prospective recovery, subject to review and approval by the Board, in each of the respective EDC’s next electric distribution base rate proceedings. The Board FURTHER ORDERS the EDCs to maintain all invoices for work performed by the LCAPP Agent as well as records associated with any and all amounts paid to the agent, for the Board’s review and consideration, should the EDCs seek recovery of the respective EDC’s portion of the LCAPP Agent’s costs. The Board FURTHER ORDERS the EDCs to defer any and all reasonably and prudently incurred costs directly associated with the LCAPP proceeding for prospective recovery, subject to review and approval by the Board in each of the respective EDC’s next electric distribution base rate proceedings.

The Board HEREBY DIRECTS Board Staff to provide Notice of Public Hearings and to conduct a minimum of four (4) Public Hearings, with at least one in each of the EDC’s service territories, at a place and time to be determined by the Presiding Officer. The Public Hearings shall be conducted by the Presiding Officer or his designee.

In addition to or in lieu of verbal comments, written comments can also be sent to the attention of the Office of the Secretary at: the New Jersey Board of Public Utilities, Two Gateway Center, Suite 801, Newark, N.J. 07102, postmarked no later than March 18, 2011 – please include the
phrase "LCAPP Law" in the subject line. Electronic comments can also be filed with the BPU at board.secretary@bpu.state.nj.us.

DATED: 2/10/11

BOARD OF PUBLIC UTILITIES
BY:

LEE A. SOLOMON
PRESIDENT

JEANNE M. FOX
COMMISSIONER

JOSSEPH L. FIORDALISO
COMMISSIONER

NICHOLAS ASSELTA
COMMISSIONER

ATTEST:

KRISTI IZZO
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.
LCAPP Agent's Report

Long-Term Capacity Agreement
Pilot Program

prepared for the

New Jersey Board of Public Utilities

March 21, 2011
# TABLE OF CONTENTS

1 Executive Summary ............................................................................................................ 1  
1.1 LCAPP Process .......................................................................................................... 1  
1.2 Economic Benefits ..................................................................................................... 2  
1.3 Environmental Benefits ............................................................................................. 4  
1.4 Community Benefits .................................................................................................. 6  

2 Procedural Background ....................................................................................................... 8  
2.1 Legislative Background ............................................................................................. 8  
2.2 Board Selection of LAI as Agent ............................................................................... 9  
2.3 Board Order ............................................................................................................. 10  
2.4 SOCA Award and Board Approval ......................................................................... 11  

3 Communications ............................................................................................................... 12  
3.1 Website .................................................................................................................... 12  
   Bidder Information ................................................................................................. 12  
   Schedule .................................................................................................................. 13  
   Questions from Participants .................................................................................... 13  
   News ....................................................................................................................... 13  
   Contact Information ................................................................................................ 14  
3.2 Announcements and Publicity ................................................................................. 14  

4 Development of Form of SOCA ....................................................................................... 15  
4.1 Stakeholder Submissions of Proposed SOCAs ........................................................ 15  
   General Terms and Conditions .............................................................................. 16  
   Risk Issues .............................................................................................................. 17  
   Payment Issues .......................................................................................................... 19  
4.2 Stakeholder Initial Comments on the Proposed Forms of SOCAs ....................... 20  
4.3 Stakeholder Reply Comments on Agent’s Draft SOCA (version 1) ....................... 21  
   Capacity Clearing Requirement .............................................................................. 22  
   Calculation of UCAP Amount to be Bid ................................................................ 23  
   Energy and Ancillary Service Bid Prices ............................................................... 23  
   Rate Recovery ......................................................................................................... 23  
   Other Issues ............................................................................................................. 24  
4.4 Stakeholder Supplemental Comments on Agent’s Draft SOCA (version 2)........... 24  
4.5 Agent's Final Proposed Form of SOCA ................................................................. 26  
4.6 LCAPP Question 64 and Generator Submissions of Modified SOCAs with Bids.. 27  

5 Prequalification Evaluation Process ................................................................................. 28  
5.1 Eligibility Screening Method ................................................................................... 28  
5.2 Prequalification Review Method ............................................................................. 28  
   Environmental Benefits .......................................................................................... 29  
   Economic Benefits ................................................................................................. 30  
   Community Benefits ............................................................................................... 31  
   Certainty of Meeting In-Service Date ..................................................................... 31
5.3 Prequalification Applications ................................................................. 36
    Application Data Sheets ......................................................................... 36
    Requests for Additional Information ....................................................... 38
5.4 Results of Eligibility Screening ............................................................ 38
5.5 Results of Prequalification Review ....................................................... 40
6 Bid Evaluation Method .............................................................................. 41
    6.1 Bid Form and Supporting Materials .................................................. 41
        SOCP Bid Form ................................................................................. 41
        Bid Security ...................................................................................... 41
        Officer Certification Form ................................................................. 41
    6.2 Summary of Bids Received ................................................................. 42
    6.3 Gross SOCA Cost .............................................................................. 43
    6.4 RCP Credit ......................................................................................... 43
    6.5 Net SOCA Cost ................................................................................. 43
    6.6 Economic Benefits to New Jersey Ratepayers .................................... 43
        PJM Electricity Market ........................................................................ 43
        Energy Market Model ........................................................................ 48
        Capacity Market Model ...................................................................... 58
    6.7 Minimum Offer Price Rule ................................................................. 61
        Procedural Matters and Chronology .................................................. 61
        PJM’s Proposed Changes ................................................................... 63
        MOPR Analysis and Risk Assessment in the Context of LCAPP .......... 65
    6.8 Price Impact Analysis ........................................................................ 65
        Energy Price Impact Analysis ............................................................ 65
        Capacity Price Impact Analysis .......................................................... 66
    6.9 Preference Weight for COD Prior to 2015 Delivery Year ..................... 66
    6.10 Net Load Cost .................................................................................. 66
    6.11 Ranking and Selection Process ........................................................ 67
        Present Value Calculations .................................................................. 67
        Consideration of Alternative SOCA Price Options ............................ 67
        Ranking of Generators based on Selected Price Options .................... 68
        Evaluation of Generator Portfolios ..................................................... 69

7 Recommendations ...................................................................................... 71
    7.1 Recommended Winners ...................................................................... 71
    7.2 Portfolio Benefits Supporting Selection .............................................. 72
        Ratepayer Economic Benefits ............................................................ 72
        Environmental Benefits ...................................................................... 72
        Community Benefits ......................................................................... 76
LIST OF FIGURES

Figure 1. Net Economic Benefits of Recommended SOCA Portfolio................................. 3
Figure 2. PJM Change in Annual Emissions of NOx and SO2 Associated with Recommended SOCA Portfolio......................................................................................... 4
Figure 3. New Jersey and PJM Change in Annual Emissions of Mercury Associated with Recommended SOCA Portfolio........................................................................... 5
Figure 4. System-wide Change in Annual Emissions of CO2 Associated with Recommended SOCA Portfolio................................................................................................. 5
Figure 5. Potential Employment Effects of Recommended Portfolio .................................. 7
Figure 6. Number of Total Website Subscribers by Day........................................................ 14
Figure 7. Average Daily On-Peak LMPs in New Jersey....................................................... 45
Figure 8. Comparison of PJM and JCPL Average Daily On-Peak LMPs............................. 45
Figure 9. Variable Resource Requirement Curve............................................................... 47
Figure 10. Historical RPM Clearing Prices........................................................................ 48
Figure 11. Cumulative Additions of Generation Capacity in PJM.................................... 60
Figure 12. New Jersey Resource Clearing Price Forecast..................................................... 61
Figure 13. Cumulative Cost v. Cumulative Capacity.......................................................... 69
Figure 14. Total Net Load Cost for Generator Portfolios..................................................... 70
Figure 15. Locations of Recommended Eligible Generators............................................. 72
Figure 16. PJM Change in Annual Emissions of NOx and SO2 Associated with Recommended SOCA Portfolio................................................................. 74
Figure 17. New Jersey Change in Annual Emissions of NOx and SO2 Associated with Recommended SOCA Portfolio................................................................. 74
Figure 18. New Jersey and PJM Change in Annual Emissions of Mercury Associated with Recommended SOCA Portfolio................................................................. 75
Figure 19. System-wide Change in CO2 Annual Emissions of CO2 Associated with Recommended SOCA Portfolio................................................................. 76
Figure 20. Potential Employment Effects of Recommended Portfolio ................................. 78
LIST OF TABLES

Table 1. Portfolio of Recommended SOCA s ................................................................. 2
Table 2. Board Ordered LCAPP Milestone Schedule ................................................... 10
Table 3. List of Applicants Submitting Prequalification Packages .............................. 37
Table 4. Eligible Generators ....................................................................................... 39
Table 5. Ineligible Generators ................................................................................... 39
Table 6. Prequalification Review Results .................................................................... 40
Table 7. Recent and Pending PJM Fossil Fuel Plant Deactivations .............................. 50
Table 8. Class I or Tier 1 Renewable Portfolio Standards for PJM States ................. 55
Table 9. Demand Response and Energy Efficiency Resources in the 2013/14 BRA ....... 57
Table 10. EDC Energy Prices Relative to PJM Average Energy Price ....................... 58
Table 11. Net CONE Calculations for 2014/15 Base Residual Auction .................... 59
Table 12. Weighted Average Cost of Capital Calculation ......................................... 67
Table 13. Recommended SOCA Awards ................................................................... 71
LIMITATION OF LIABILITY

This report has been prepared for the New Jersey Board of Public Utilities for the sole purpose of documenting the efforts of Levitan & Associates, Inc., the Long-Term Capacity Agreement Pilot Program (LCAPP) Agent, to solicit, evaluate, and recommend new base load and mid-merit generation in conformance with the LCAPP Law. The findings and conclusions contained herein depend on the assumptions identified in this report. While Levitan & Associates, Inc. believes these assumptions to be reasonable, there is no assurance that any specific assumption will actually occur and we make no assurances except those explicitly set forth herein. Levitan & Associates, Inc. does not make any warranty, expressed or implied, with respect to the use of information or methods disclosed in this report, and does not assume any liability with respect to the use of information or methods disclosed in this report.
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO</td>
<td>Atlantic City Electric Company zone</td>
</tr>
<tr>
<td>AEP</td>
<td>American Electric Power Company zone</td>
</tr>
<tr>
<td>APS</td>
<td>Allegheny Power System zone</td>
</tr>
<tr>
<td>ATSI</td>
<td>American Transmission Systems Inc.</td>
</tr>
<tr>
<td>BACT</td>
<td>Best Available Control Technology</td>
</tr>
<tr>
<td>Bill</td>
<td>Senate Bill No. 2381</td>
</tr>
<tr>
<td>Board</td>
<td>New Jersey Board of Public Utilities</td>
</tr>
<tr>
<td>BRA</td>
<td>Base Residual Auction</td>
</tr>
<tr>
<td>CATR</td>
<td>Clean Air Transport Rule</td>
</tr>
<tr>
<td>CC</td>
<td>Combined Cycle</td>
</tr>
<tr>
<td>CETL</td>
<td>Capacity Emergency Transfer Limit</td>
</tr>
<tr>
<td>CETO</td>
<td>Capacity Emergency Transfer Objective</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>COD</td>
<td>Commercial Operation Date</td>
</tr>
<tr>
<td>COMED</td>
<td>Commonwealth Edison Company zone</td>
</tr>
<tr>
<td>CONE</td>
<td>Cost of New Entry</td>
</tr>
<tr>
<td>Con Ed</td>
<td>Consolidated Edison Company</td>
</tr>
<tr>
<td>CT</td>
<td>Combustion Turbine</td>
</tr>
<tr>
<td>DAM</td>
<td>Day Ahead Market</td>
</tr>
<tr>
<td>DAY</td>
<td>Dayton Power &amp; Light Company zone</td>
</tr>
<tr>
<td>DOM</td>
<td>Dominion Virginia Power zone</td>
</tr>
<tr>
<td>DPL</td>
<td>Delmarva Power and Light Company zone</td>
</tr>
<tr>
<td>DR</td>
<td>Demand Response</td>
</tr>
<tr>
<td>DUQ</td>
<td>Duquesne Light Company zone</td>
</tr>
<tr>
<td>EAS</td>
<td>Energy &amp; Ancillary Services</td>
</tr>
<tr>
<td>EDC</td>
<td>Electric Distribution Company</td>
</tr>
<tr>
<td>EE</td>
<td>Energy Efficiency</td>
</tr>
<tr>
<td>EMAAC</td>
<td>Eastern Mid-Atlantic Area Council</td>
</tr>
<tr>
<td>EMP</td>
<td>Energy Master Plan</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
</tr>
<tr>
<td>EPC</td>
<td>Engineering, Procurement and Construction</td>
</tr>
<tr>
<td>EPT</td>
<td>Eastern Prevailing Time</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>FT</td>
<td>Firm Transportation</td>
</tr>
<tr>
<td>FTE</td>
<td>Full Time Equivalent</td>
</tr>
<tr>
<td>FTWR</td>
<td>Firm Transmission Withdrawal Right</td>
</tr>
<tr>
<td>GT</td>
<td>Gas Turbine</td>
</tr>
<tr>
<td>GW</td>
<td>Gigawatt</td>
</tr>
<tr>
<td>HTP</td>
<td>Hudson Transmission Project</td>
</tr>
<tr>
<td>IMM</td>
<td>Independent Market Monitor</td>
</tr>
<tr>
<td>ISDA</td>
<td>International Swaps and Derivatives Association</td>
</tr>
<tr>
<td>JCPL</td>
<td>Jersey Central Power and Light Company</td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatt</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>LAER</td>
<td>Lowest Achievable Emission Rate</td>
</tr>
<tr>
<td>LAI</td>
<td>Levitan &amp; Associates, Inc.</td>
</tr>
<tr>
<td>LC</td>
<td>Letter of Credit</td>
</tr>
<tr>
<td>LCAPP</td>
<td>Long-Term Capacity Agreement Pilot Program</td>
</tr>
<tr>
<td>LCAPP Law</td>
<td>P.L. 2011, c. 9</td>
</tr>
<tr>
<td>LDA</td>
<td>Locational Deliverability Area</td>
</tr>
<tr>
<td>LMP</td>
<td>Locational Marginal Price</td>
</tr>
<tr>
<td>MAAC</td>
<td>Mid-Atlantic Area Council</td>
</tr>
<tr>
<td>MACT</td>
<td>Maximum Achievable Control Technology</td>
</tr>
<tr>
<td>MAPP</td>
<td>Mid-Atlantic Power Pathway</td>
</tr>
<tr>
<td>MD PSC</td>
<td>Maryland Public Service Commission</td>
</tr>
<tr>
<td>METED</td>
<td>Metropolitan Edison Company zone</td>
</tr>
<tr>
<td>MOPR</td>
<td>Minimum Offer Price Rule</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
</tr>
<tr>
<td>NJDEP</td>
<td>New Jersey Department of Environmental Protection</td>
</tr>
<tr>
<td>NLC</td>
<td>Net Load Cost</td>
</tr>
<tr>
<td>NOx</td>
<td>Nitrogen Oxides</td>
</tr>
<tr>
<td>NYISO</td>
<td>New York Independent System Operator</td>
</tr>
<tr>
<td>NYPA</td>
<td>New York Power Authority</td>
</tr>
<tr>
<td>PATH</td>
<td>Potomac Appalachian Transmission Highline</td>
</tr>
<tr>
<td>PECO</td>
<td>PECO Energy Company zone</td>
</tr>
<tr>
<td>Penelec</td>
<td>Pennsylvania Electric Company zone</td>
</tr>
<tr>
<td>PILOT</td>
<td>Payment In Lieu Of Taxes</td>
</tr>
<tr>
<td>PJM</td>
<td>PJM Interconnection, Inc.</td>
</tr>
<tr>
<td>PM</td>
<td>Particulate Matter</td>
</tr>
<tr>
<td>PPL</td>
<td>PPL Electric Utilities Corporation zone</td>
</tr>
<tr>
<td>PSEG</td>
<td>Public Service Electric and Gas Company</td>
</tr>
<tr>
<td>PV</td>
<td>Present Value</td>
</tr>
<tr>
<td>RCP</td>
<td>Resource Clearing Price</td>
</tr>
<tr>
<td>RECO</td>
<td>Rockland Electric Company</td>
</tr>
<tr>
<td>RFC</td>
<td>Reliability First Corporation</td>
</tr>
<tr>
<td>RPM</td>
<td>Reliability Pricing Model</td>
</tr>
<tr>
<td>RPS</td>
<td>Renewable Portfolio Standard</td>
</tr>
<tr>
<td>RTEP</td>
<td>Regional Transmission Expansion Plan</td>
</tr>
<tr>
<td>RTM</td>
<td>Real Time Market</td>
</tr>
<tr>
<td>RTO</td>
<td>Regional Transmission Organization</td>
</tr>
<tr>
<td>SCR</td>
<td>Selective Catalytic Reduction</td>
</tr>
<tr>
<td>SERC</td>
<td>SERC Reliability Corporation</td>
</tr>
<tr>
<td>SIS</td>
<td>System Impact Study</td>
</tr>
<tr>
<td>SO2</td>
<td>Sulfur Dioxide</td>
</tr>
<tr>
<td>SOCA</td>
<td>Standard Offer Capacity Agreement</td>
</tr>
<tr>
<td>SOCP</td>
<td>Standard Offer Capacity Price</td>
</tr>
<tr>
<td>TNLC</td>
<td>Total Net Load Cost</td>
</tr>
<tr>
<td>TNW</td>
<td>Tangible Net Worth</td>
</tr>
<tr>
<td>TrAIL</td>
<td>Trans-Allegheny Interstate Line</td>
</tr>
<tr>
<td>UCAP</td>
<td>Unforced Capacity</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Full Form</td>
</tr>
<tr>
<td>--------------</td>
<td>-----------</td>
</tr>
<tr>
<td><strong>UNLC</strong></td>
<td>Unit Net Load Cost</td>
</tr>
<tr>
<td><strong>VACAR</strong></td>
<td>Virginia and the Carolinas</td>
</tr>
<tr>
<td><strong>VRR</strong></td>
<td>Variable Resource Requirement</td>
</tr>
<tr>
<td><strong>WACC</strong></td>
<td>Weighted Average Cost of Capital</td>
</tr>
</tbody>
</table>
1 EXECUTIVE SUMMARY

1.1 LCAPP Process

On January 28, 2011, Governor Christopher Christie signed into law P.L. 2011, c. 9, amending and supplementing P.L. 1999, c. 23 (LCAPP Law), establishing a Long-Term Capacity Agreement Pilot Program (LCAPP) to promote the construction of base load and mid-merit electric generation facilities for the benefit of New Jersey’s electric consumers. On February 10, 2011, the New Jersey Board of Public Utilities (Board) issued an Order initiating a proceeding to implement the actions required by the LCAPP Law and selecting Levitan & Associates, Inc. (LAI) as the LCAPP Agent. In the role of LCAPP Agent, LAI has had the responsibility for assisting the Board with establishment of the LCAPP, prequalifying eligible generators, and submitting recommendations for the Board’s consideration.

The primary activities undertaken by LAI acting as the Board’s Agent have been fourfold:

- First, to coordinate with the Board in order to implement the goals of the LCAPP in an impartial, objective and transparent manner in strict accord with standards of professional excellence.

- Second, to develop the form of Standard Offer Capacity Agreement (SOCA) that achieves a fair and reasonable balance between the interests of generators and those of New Jersey’s electric distribution companies (EDCs) and ratepayers.

- Third, to evaluate generators participating in the LCAPP through the eligibility, prequalification, and commercial proposal stages.

- Fourth, to formulate recommendations for Board consideration that select winning bids among the field of eligible and prequalified bidders based on the evaluation criteria set forth in the LCAPP Law.

Regarding the first objective, LCAPP implementation in an impartial, objective, and transparent manner, LAI has taken action to maximize bidder interest and participation. LAI has ensured that all bidders have access to the same information. LAI has considered proposals reflecting different technology types and locations, including resources outside New Jersey. LAI has applied the same qualitative and quantitative criteria in a consistent and objective manner. All communication with rival generators and EDCs has been administered through the LCAPP website.

Regarding the second objective, developing the SOCA, LAI has ensured that rival stakeholders have had reasonable opportunity to express their concerns about various commercial, regulatory, operational, and risk-related provisions affecting the allocation of risk and reward between seller and buyer. While milestone constraints set forth in the LCAPP Law necessitated expedited preparation of the contract, the SOCA development process was based on multiple rounds of SOCA drafts and stakeholder comments. In the Agent’s view, the final SOCA achieved a fair and reasonable balance between the interests of the EDCs on behalf of New Jersey’s ratepayers and generators. All SOCA development activities, including review of stakeholder comments
and preparation of Agent SOCA versions, including the final proposed form of SOCA, were undertaken by LAI in conjunction with Board Staff and Counsel.

Regarding the third objective, the evaluation of generators’ proposals through the eligibility, prequalification and commercial proposal stages, LAI has formulated a multi-stage evaluation process consistent with the LCAPP Law that is centered on the maximization of economic, environmental and community benefits from the standpoint of ratepayers in New Jersey. Applicants were first reviewed in light of the requirements in the LCAPP Law to be an eligible generator. Eligible generators were then further reviewed to determine whether they should be prequalified on the basis of showing environmental, economic and community benefits, and the demonstration of meeting the proposed in-service date with reasonable certainty. The evaluation of commercial proposals was completed in parallel with the prequalification review.

Regarding the fourth objective, the selection of winning bids, LAI has performed rigorous qualitative and quantitative analysis in order to identify those projects best positioned to confer economic, environmental, and community benefits in New Jersey. Consistent with the procurement guidelines, in particular, fairness and objectivity, LAI has evaluated the conforming Standard Offer Capacity Price (SOCP) bids from eligible generators. LAI identified three generation facilities to be recommended for SOCA awards. The total unforced capacity (UCAP) associated with the recommended SOCA awards is 1,948.5 MW, as shown in Table 1.

<table>
<thead>
<tr>
<th>Table 1. Portfolio of Recommended SOCAs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Newark Energy Center: Hess Newark, LLC</td>
</tr>
<tr>
<td>Unforced Capacity: 625.0 MW</td>
</tr>
<tr>
<td>Location: Newark, NJ</td>
</tr>
<tr>
<td>Technology Type: Combined Cycle</td>
</tr>
<tr>
<td>Fuel Type: Natural Gas</td>
</tr>
<tr>
<td>First SOCA Year: 2016-2017</td>
</tr>
<tr>
<td>Selected Pricing Option: Option B</td>
</tr>
<tr>
<td>Term: 15 years</td>
</tr>
<tr>
<td>-----------------------------------------</td>
</tr>
<tr>
<td>Old Bridge Clean Energy Center: New Jersey Power Development LLC</td>
</tr>
<tr>
<td>Unforced Capacity: 660.1 MW</td>
</tr>
<tr>
<td>Location: Old Bridge, NJ</td>
</tr>
<tr>
<td>Technology Type: Combined Cycle</td>
</tr>
<tr>
<td>Fuel Type: Natural Gas</td>
</tr>
<tr>
<td>First SOCA Year: 2015-2016</td>
</tr>
<tr>
<td>Selected Pricing Option: $11 Initial Year then Tapered</td>
</tr>
<tr>
<td>Term: 15 years</td>
</tr>
<tr>
<td>-----------------------------------------</td>
</tr>
<tr>
<td>Woodbridge Energy Center: CPV Shore, LLC</td>
</tr>
<tr>
<td>Unforced Capacity: 663.4 MW</td>
</tr>
<tr>
<td>Location: Woodbridge, NJ</td>
</tr>
<tr>
<td>Technology Type: Combined Cycle</td>
</tr>
<tr>
<td>Fuel Type: Natural Gas</td>
</tr>
<tr>
<td>First SOCA Year: 2015-2016</td>
</tr>
<tr>
<td>Selected Pricing Option: Option #2, Gas-only</td>
</tr>
<tr>
<td>Term: 15 years</td>
</tr>
</tbody>
</table>

1.2 **ECONOMIC BENEFITS**

LAI determined that the recommended SOCA portfolio of the Newark Energy Center, Old Bridge Clean Energy Center, and Woodbridge Energy Center offers substantial net economic benefits.

---

1 “Counsel” as used throughout this report refers to Board Staff counsel and the assigned New Jersey Deputy Attorney General.
2 Represents pricing option names as provided by bidders.
benefits on an expected value basis over the relevant planning horizon to New Jersey’s electric customers. These net economic benefits are ascribable to the expected value of the recommended SOCA portfolio in relation to the forecasted capacity market clearing price under PJM’s Base Residual Auction (BRA), as well as the reduction in wholesale energy prices in New Jersey, all other things being the same. Other economic benefits are also likely to be realized by benefited load and host communities in New Jersey, but have not been counted. The net economic benefits associated with the recommended SOCA portfolio are illustrated in Figure 1 on a present value (PV) basis. Figure 1 also indicates how the portfolio has been constructed, starting on the left with the lowest unit net cost SOCA, i.e., the SOCA capacity cost net of market capacity prices, expressed in dollars per kilowatt ($/kW), then adding the SOCA with the second lowest unit net cost, and, finally, adding the SOCA with the third lowest unit net cost. Formulation of the recommended portfolio on the right-hand side is bound by the target procurement of 2,000 MW, but is also constrained by the identification of additional SOCAs that confer incremental economic benefits, i.e., reduction in total net load cost.

In reviewing the results reported in Figure 1, the red segment above the x-axis represents the PV of the SOCA payments over the recommended 15-year SOCA term for the first SOCA, then the first and second SOCA, and, finally, on the right-hand side, the recommended portfolio. The blue segment below the x-axis represents the PV of the expected credits to ratepayers in New Jersey ascribable to the financial settlement of the SOCA capacity through PJM’s BRA over the 15-year SOCA term for each project. Finally, the yellow segment represents the PV of the energy price benefit over the 15-year SOCA term.3

Figure 1. Net Economic Benefits of Recommended SOCA Portfolio

For a variety of reasons, LAI has not counted any capacity market price benefits over the planning horizon. Therefore, there is no green segment acknowledged in this analysis.
From the standpoint of ratepayers in New Jersey, the recommended SOCA portfolio is deep-in-the-black: on an expected value basis the PV of the net economic benefit over 15-years is $1.8 billion.\(^4\)

1.3 **Environmental Benefits**

LAI has determined that the recommended SOCA portfolio offers significant environmental benefits to New Jersey’s electric customers. These environmental benefits are ascribable to the displacement of incumbent generation with a portfolio of cleaner, more efficient gas-fired generation. The average net annual reductions of these pollutants and greenhouse gases are significant. Overall, the annual reductions are equivalent, on an order-of-magnitude basis, to the annual emissions of roughly 250-MW of coal-fired generation at a 100% capacity factor.

As shown in Figure 2, this displacement will result in lower emissions of NO\(_x\) and SO\(_2\) across the PJM region. Regional reductions in NO\(_x\) and SO\(_2\) will contribute to cleaner air for New Jersey, since these pollutants are precursors in the formation of ozone and haze, which are transported from upwind states in PJM to New Jersey.

![Figure 2. PJM Change in Annual Emissions of NO\(_x\) and SO\(_2\) Associated with Recommended SOCA Portfolio\(^5\)](image)

As shown in Figure 3, net emission of mercury will be reduced regionally as well as locally in New Jersey.

\(^4\) Other value enhancements ascribable to (1) environmental benefits, (2) the economic value associated with the construction and operation of the new generation facilities, and (3) host community benefits have not been included in the derivation of the $1.8 billion benefit to load.

\(^5\) Figure 2, Figure 3, and Figure 4 are shown on a calendar year basis.
CO₂, the principal greenhouse gas, is a global environmental concern, and therefore must be viewed from the system-wide perspective across the entire modeled area, as shown in Figure 4. The recommended SOCA portfolio displaces more carbon-intensive oil or coal-fired generation and/or less efficient gas-fired generation across the modeled system, thereby giving rise to a net reduction in CO₂ emissions in each year of the forecast.

Figure 4. System-wide Change in Annual Emissions of CO₂ Associated with Recommended SOCA Portfolio
All of the recommended projects propose to use state-of-the-art evaporative cooling tower systems, minimizing the use and discharge of cooling water. In addition, two of the three projects, the Newark Energy Center and the Woodbridge Energy Center, will be located on brownfield sites. The beneficial reuse of formerly impaired properties represents a significant environmental benefit that may ultimately confer additional economic benefits as well.

1.4 **COMMUNITY BENEFITS**

LAI has determined that the recommended SOCA portfolio offers substantial socio-economic benefits to the State of New Jersey on an expected value basis. These benefits are primarily due to the expansion of direct employment for the duration of the associated construction phases of the projects and the new on-site permanent jobs associated with operation and maintenance of the new generation facilities during their operating lives. In addition, New Jersey employment and personal income and business revenues are expected to increase due to the indirect (supply chain) and induced (re-spending) impacts of increasing the demand for goods and services procured from New Jersey firms during the construction and operations phases. This dynamic is often referred to as an economic activity multiplier effect and belongs in the summarization of benefits despite the uncertainty associated with predicting construction and operational phase jobs, and income-related benefits. Estimates of (a) the temporary construction-related employment gains and (b) operations-related permanent jobs are shown in Figure 5. For all three facilities, based upon the data provided by the three recommended eligible generators, approximately 2,400 construction jobs over a three-year period would be created, and up to nearly 5,900 indirect plus induced job-years, also spanning about three years. During operation, the three facilities would directly provide nearly 80 full-time equivalent (FTE) workers, plus up to another 160 FTE New Jersey jobs via multiplier effects.\(^6\) However, in the current high unemployment setting, the multiplier effects during the construction period could be substantially less than indicated in Figure 5 if a large share of the jobs go to unemployed or underemployed workers, who may pay down debt and not make major purchases, such as buying homes. Later, by the time the facilities are in operation, lower forecast unemployment should allow most of the modeled multiplier effects to be realized. Though not quantified, an additional economic benefit to New Jersey’s electric customers during the operational phase is the expected reduction in wholesale power costs which should be passed on to electric customers, thereby giving rise to increased spending on other goods and services.

\(^6\) These calculations are based on the definition that one FTE “job-year” is equivalent to 1,820 labor hours.
Figure 5. Potential Employment Effects of Recommended Portfolio

(a) Construction – Cumulative

(b) Operations – Annual

The economic, environmental, and socio-economic results presented in the Agent’s Report represent LAI’s expected outcome over the 15-year SOCA term evaluated during the course of the LCAPP procurement process. Complex and dynamic market, regulatory, legislative and operating forces may result in significantly different economic, environmental and socio-economic outcomes. While the recommended SOCA portfolio is likely to confer large and robust net economic benefits to load, *i.e.*, ratepayers, in New Jersey, actual results may be significantly different.

---

7 Note that the y-axis scales for the two charts in Figure 5 are different.
2 PROCEDURAL BACKGROUND

2.1 LEGISLATIVE BACKGROUND

Senate Bill No. 2381 (Bill), the legislation creating the LCAPP, “establishes a long-term capacity agreement pilot program to promote construction of qualified electric generation facilities.” The Bill was originally introduced in the New Jersey Legislature on October 18, 2010, sponsored by Senator Bob Smith (District 17 – Middlesex and Somerset) and Senator Christopher “Kip” Bateman (District 16 – Morris and Somerset). As originally proposed, the Bill defined an eligible generator as “a developer of a new, natural gas fired, combined-cycle electric power generating facility with a net summer output rating of 100 megawatts or larger, that is physically located within the State of New Jersey, and that commences construction after the effective date of P.L. ___, c. ___ (C. ___) (pending before the legislature as this Bill).” The originally proposed minimum SOCA term was 15 years, the target volume to be procured was 500 to 1,500 MW, and generators were limited to a maximum SOCA volume of 900 MW.

On November 15, 2010, the Senate Environment and Energy Committee reported the Bill favorably with committee amendments. In addition to changes to the findings and declarations section and to certain of the added definitions, and technical corrections, these amendments made the following significant revisions:

- Reduced the maximum amount of capacity to be procured from 1,500 MW to 1,000 MW; and
- Deleted the limitation that no single generator could enter into more than 900 MW of SOCAs.

On December 13, 2010, the Assembly Telecommunications and Utilities Committee reported the Bill favorably with further committee amendments. In addition to changes to the findings and declarations section and to certain of the added definitions, and technical corrections, these amendments made the following significant revisions:

- Deleted the requirement for eligible generators to be new, natural gas fired, and combined cycle (CC);
- Added language requiring eligible generators to be base load generating facilities;
- Deleted the requirement for eligible generators to have net summer output ratings greater than 100 MW;
- Deleted the requirement for eligible generators to be physically located in the State of New Jersey;
- Reduced the maximum amount of capacity to be procured from 1,500 MW to 1,000 MW;
- Required that no single generator enter into more than 700 MW of SOCAs;
• Required the Board to retain an Agent to assist with development and implementation of the LCAPP; and
• Added language allowing the Board to suspend the LCAPP in the event of administrative or judicial challenges.

On January 6, 2011, an Assembly Floor Amendment proposed by Assemblyman Upendra J. Chivukula (District 17 – Middlesex and Somerset) was adopted. This amendment increased the amount of capacity to be procured from 1,000 MW to 2,000 MW.

On January 10, 2011, additional Assembly Floor Amendments proposed by Assemblyman Chivukula were adopted. In addition to technical corrections and changes to definitions, the amendments made the following significant revisions to the Bill:

• Deleted language excluding combustion turbine generation facilities directly interconnected with EDC transmission or distribution systems from the eligible generator definition;
• Added language including mid-merit resources in the eligible generator definition;
• Revised the SOCA definition to replace specific terms of years with a term to be determined by the Board not to exceed 15 years;
• Replaced specific procedural dates with timeframes;
• Eliminated the weighted preference for eligible generators located in areas in need of redevelopment or brownfield areas; and
• Provided a weighted preference for eligible generators that can enter commercial operation for delivery year 2015.

Following these final amendments, the Bill was passed by both the Assembly and the Senate on January 10, 2011, and was signed by Governor Christie on January 28, 2011.

2.2 BOARD SELECTION OF LAI AS AGENT

LAI submitted a proposal to serve as LCAPP Agent to the EDCs on February 4, 2011. The EDCs reviewed all proposals, and submitted a recommendation to the Board on February 7, 2011, to select LAI as the LCAPP Agent. Following this recommendation, a Notice for Solicitation of Comments was posted to the Board’s website, with comments due by 12:00 noon EST on February 9, 2011. As stated in the February 10, 2011 Order (at p. 4), no comments were received. In the Order, the Board authorized the EDCs to retain LAI as LCAPP Agent and to reimburse the Agent for its work in connection with the LCAPP proceeding.

Following the EDCs’ recommendation to the Board to select LAI as LCAPP Agent, no further direct communication took place between the Agent and representatives of the EDCs. All
communication thereafter was indirect, through the LCAPP website established by the Agent and email updates sent to all website subscribers.

The Agent is not “acting on behalf of the EDCs” in the LCAPP proceeding. Consistent with the LCAPP Law, LAI has been retained by the EDCs to work solely for the Board. According to the LCAPP Law, the Agent assists the Board in its LCAPP review process. The EDCs have no control over, influence, or communication with the Agent in this proceeding. LAI’s retention by the EDCs is an administrative arrangement whereby the EDCs can provide timely payments to LAI for work performed on behalf of the Board.8

2.3 BOARD ORDER

The Order instituting the LCAPP proceeding was issued on February 10, 2011.9 The Order provides background on the LCAPP Law and summarizes the responsibilities of the Agent and the Board in the LCAPP matter. The Order adopted the milestone schedule for the proceeding, shown in Table 2.

<table>
<thead>
<tr>
<th>Milestone Event</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed SOCA Submission</td>
<td>2/14/2011</td>
</tr>
<tr>
<td>Application Data Sheets Issued by Agent</td>
<td>2/15/2011</td>
</tr>
<tr>
<td>Application Data Sheets Due</td>
<td>2/22/2011</td>
</tr>
<tr>
<td>Initial Comments to Proposed Form of SOCA</td>
<td>2/22/2011</td>
</tr>
<tr>
<td>Reply Comments to Proposed Form of SOCA</td>
<td>2/25/2011</td>
</tr>
<tr>
<td>Final Form of SOCA Issued</td>
<td>3/1/2011</td>
</tr>
<tr>
<td>Final SOCP Bids Due</td>
<td>3/7/2011</td>
</tr>
<tr>
<td>Initial Recommended SOCA Proposals</td>
<td>3/15/2011</td>
</tr>
<tr>
<td>Issue Agent’s Report Supporting Selection</td>
<td>3/21/2011</td>
</tr>
<tr>
<td>Public Comments on Agent’s Report</td>
<td>3/24/2011</td>
</tr>
<tr>
<td>Board Order on Recommended SOCAs10</td>
<td>3/29/2011</td>
</tr>
</tbody>
</table>

The Order further describes the types of information to be requested / submitted through the prequalification process, and states a requirement for participants to furnish additional information requested by the Agent within three business days. With regard to the SOCA preparation process, the Order lays out the commenting schedule and instructions for submitting binding SOCP bids based on the final form of SOCA. Aside from the SOCA written comment process, the public has had the opportunity to comment on the LCAPP at a series of Public

8 Source: http://www.nj-lcapp.com/qa.html#q58
10 This date was moved from the original date of March 30, 2011.
Hearings held in the EDCs’ respective service territories, and also via written comments to the Board.

2.4 SOCA AWARD AND BOARD APPROVAL

Following issuance of this report, including comments and revision, if necessary, the Board will issue an order on the Agent’s recommendations and the form of SOCA on March 29, 2011. The LCAPP Law calls for the SOCA(s) resulting from the proceeding to be awarded and executed no later than 30 days after the approval of the form of the SOCA. The SOCA execution deadline is April 28, 2011.
3 COMMUNICATIONS

All communication with prospective bidders and other parties was handled electronically through the secure LCAPP website and email. All email communications were handled through a single address (agent@nj-lcapp.com) in order to maintain a complete record of communications with stakeholders.

3.1 WEBSITE

The LCAPP website was launched on February 10, 2011, at http://www.nj-lcapp.com. General categories of information available through the website are described in the following sections. All information on the website was publicly available, with all submission of generator-specific information, including Prequalification Applications and commercial proposals, handled through a secure upload protocol in order to maintain data security.

Bidder Information

The Bidder Information section of the website served as the central location of information relating to participation in the LCAPP, with four categories of materials: background documents, SOCA, prequalification, and bidding. The Background Documents section included links to the LCAPP Law and the Order. In the SOCA section of the website, participants could submit their proposed SOCA forms, which were due by February 14, 2011. All submissions were posted to the website. Following the February 22, 2011 and February 25, 2011 comment submission deadlines, participant comments were also posted to the Bidder Information page for public review. Additional opportunities for comment were provided to participants, so this section of the website was expanded to include postings of Supplemental Reply Comments (due on March 1, 2011) and Technical Comments (unsolicited). The draft and final SOCAs, prepared by the Agent and Board Staff and Counsel were also posted on the website: the initial draft on February 23, 2011, the revised draft on February 28, 2011, and the final version on March 1, 2011.

Three separate Prequalification Application documents were posted to the website on February 14, 2011: the Application Data Sheets, Attachment 1 to Part A of the Application Data Sheets, and Attachments 2 through 6 to Part A of the Application Data Sheets. Instructions for submitting these forms were also posted to the website, along with an upload point for submitting the completed forms to the LCAPP Agent.

The SOCP bid form, Letter of Credit (LC) form and instructions, and Officer Certification Form were posted to the website on February 23, 2011. Similarly to the prequalification materials, SOCP bids were submitted through a secure upload point on the website. LCs and Officer Certification Forms were submitted initially by email or fax, with originals subsequently delivered to the Agent.

11 Attachment 1 was separated from Attachments 2-6 because generation projects with multiple sponsors were required to submit a separate Attachment 1 for each project sponsor.
Schedule

The milestone schedule shown in Table 2 is reproduced on the website, with minor additions and revisions including the change to the date of the Board Order on Recommended SOCA (moved from March 30, 2011 to March 29, 2011) and the addition of interim SOCA postings and comment deadlines.

Questions from Participants

All participants had the opportunity to submit questions to the website via the “Submit a Question” feature. The Agent edited the questions, as necessary, to conceal the identity of the submitter prior to posting them on the website. The Agent endeavored to post responses in as timely a manner as possible. As of March 21, 2011, all submitted questions have been answered and posted to the website. Questions submitted by means other than the “Submit a Question” feature were answered by Agent as schedule permitted.

A total of 75 questions were posted to the website from the start of the LCAPP through March 21, 2011. The questions covered a broad range of topics, including clarification of the definition of an “eligible generator” in the LCAPP Law, timeline and procedural matters, confidentiality of submitted materials, and interpretation of SOCA language.12 For procedural questions, the Agent generally prepared responses independently. More complex or interpretative questions were discussed with Board Staff and Counsel prior to posting answers. Answers to the majority of questions were posted within 24 hours of receipt, although in some cases questions requiring more in-depth consideration required more than 24 hours from receipt of the question to the posting of the response. In addition to questions submitted by participants, the Agent independently prepared additional questions and responses in order to clarify procedural aspects.

News

Each update to the website was listed on the “News” section of the website in order to alert visitors to access the latest available information. Updates included the posting of new materials for review, updated milestones, and new Q&As. The website was generally updated at least once each business day through March 18, 2011. On many days there were multiple updates as new information was made available.

Interested parties had the opportunity to complete a form on the home page of the website to subscribe to email updates of new postings. Regular updates were sent to the electronic subscription list. A refreshed list of new information was frequently posted on the website. As of March 21, 2011, 165 individual parties, representing approximately 87 entities, had subscribed to the website, cumulatively distributed as shown in Figure 6.

12 A complete list of the answered questions can be found at: http://www.nj-lcapp.com/qa.html
Contact Information

Bidders were provided with links to the Board website, the LCAPP Agent’s email address, and the subscription and question submission features of the website.

3.2 ANNOUNCEMENTS AND PUBLICITY

The LCAPP launch was publicized in Platts’ *Megawatt Daily*. The half-page ad ran on the back page of the February 14, 2011, issue of *Megawatt Daily*, which was distributed electronically to subscribers on February 11, 2011. The ad was developed using a collaborative process between the LCAPP Agent and Board Staff, and included general information and selected milestones from the Board Order, along with a link to the LCAPP website.

In addition to the ad in *Megawatt Daily*, the Agent also publicized the launch of the LCAPP with a series of email transmissions or “blasts” to the PJM Members Committee roster. This roster is posted publicly on the PJM website, and includes contact information for approximately 1000 individuals.13 Email blasts were distributed on February 11, 2011, February 15, 2011, and February 18, 2011.

In addition to communications initiated by the LCAPP Agent, the Board Order was published on the Board website. The Order directed the EDCs to post the Order to their websites and distribute it to their respective Basic Generation Suppliers.

---

13 [http://pjm.com/~/media/committees-groups/rosters/members-roster.ashx](http://pjm.com/~/media/committees-groups/rosters/members-roster.ashx)
4 DEVELOPMENT OF FORM OF SOCA

The Agent solicited input from all website subscribers across multiple phases. First, interested parties were asked to submit draft forms of the SOCA by February 14, 2011. Initial comments on the draft forms of SOCA were subsequently due on February 22, 2011. The initial draft of the Agent’s SOCA was issued on February 23, 2011. The Agent notified stakeholders that Reply Comments were due on February 25, 2011. A revised draft of the Agent’s SOCA was posted on February 28, 2011. Stakeholders were given a final opportunity to submit Supplemental Reply Comments the next day by 12:30 pm Eastern Prevailing Time (EPT) on March 1, 2011 and the final SOCA was posted on the LCAPP website by the close of business on March 1, 2011.

4.1 STAKEHOLDER SUBMISSIONS OF PROPOSED SOCAS

Under the Order, stakeholders were requested to provide Proposed SOCAs by February 14, 2011. The LCAPP Law specifically refers to a “...long-term financially-settled SOCA for a term...not to exceed 15 years...” Three stakeholders submitted Proposed SOCAs, two stakeholders submitted comments with Proposed SOCAs, and one stakeholder submitted just comments, all by the February 14, 2011 deadline per the Order. One of the Proposed SOCAs submitted was specifically tailored for LCAPP, two used an International Swap and Derivatives Association (ISDA) form, and two used a financially-settled draft Contract for Differences that had been issued by the Maryland Public Service Commission (MD PSC). The six submittals were as follows:

- NJ EDCs Draft SOCA specifically tailored to LCAPP
- LS Power ISDA-type form with separate confirmation
- Exelon ISDA-type form with separate confirmation
- CPV Shore, LLC Comments with modified MD PSC draft contract
- Div. of Rate Counsel Comments with MD PSC draft contract as an example
- Hess Corp. Comments

The Agent reviewed, in detail, all of the information provided by these stakeholders. The Agent then reviewed the key terms and conditions with Board Staff and Counsel. Central focus was placed on three broad categories of commercial issues, as follows (in no particular order):

---

14 LAI posted this request for stakeholders and reiterated this request in the response to Question 1 on the LCAPP website.

15 The ISDA form is widely used for financial transactions between parties in different jurisdictions and involving different currencies. The ISDA Master Agreement specifies the overarching terms and conditions that cover all transactions, while specific transaction terms are specified in confirmations that are appended to the Master Agreement. It is not unusual for a Master Agreement between two parties to cover hundreds of confirmations. The draft Contract for Differences was issued by the MD PSC on December 29, 2010, pursuant to Case No. 9214.
• General Terms and conditions (contract form, effective date, representations and warranties, etc.);

• Risk Issues (Commercial Operation Date, or “COD,” delay, failure to bid or clear in a BRA, financial security, etc.); and

• Payment Issues (calculation methodology, price and quantity definitions, etc.).

**General Terms and Conditions**

Based on a review of the EDCs’ Proposed SOCA, LAI found that it had three distinct advantages compared to the other contractual forms: (i) it was tailored to the LCAPP solicitation, i.e. a financially-settled contract for capacity in which the generator bears the vast majority of risks and the EDC buyers do not actually purchase that capacity, (ii) it conformed to many of the specific provisions in the LCAPP Law, and (iii) it contained terms and conditions that are appropriate for regulated entities.

While an ISDA-type form is often used for financial transactions, including financially-settled transactions, in LAI’s view the ISDA-type form had certain disadvantages: (i) it is better suited to financial institutions and dealers than regulated entities that must consider utility and PJM market rules; and, (ii) it is better suited for multiple confirmations under a single Master Agreement as opposed to the single transaction envisioned under the LCAPP.

The MD PSC contract was designed as a Contract for Differences under which the Buyer makes payments to assure the Supplier of fixed capacity, energy, and ancillary services prices, but does not take title to the products. This is broader than the SOCA, a financially settled capacity-only product. Many Supplier provisions (referenced in footnote 16) are not required under the LCAPP, and thus are not appropriate for the SOCA. In addition, under the SOCA, LAI believes that the generators will have the necessary financial incentives to properly design, construct, and operate the facility.

Based on the foregoing review of SOCA forms, LAI found that the EDCs’ draft SOCA was preferable to an ISDA form or the MD PSC contract. After reviewing this suggestion with Board Staff and Counsel, LAI elected to adopt the EDCs’ proposed form of SOCA for purposes of drafting a contract form that would achieve a reasonable balance between buyer and seller interests in accord with the LCAPP Law. The specific changes that were suggested to the EDCs’ draft SOCA are described below, along with the rationale behind the incorporation of many changes to achieve a reasonable balance between the competing interests of the EDCs on behalf of New Jersey’s ratepayers and generators.

---

16 In addition, many risks are passed on to the buyer in the MD PSC contract, which consequently contains sundry provisions assuring the buyer of appropriate project design, construction, timing, operation, and performance, as well as monitoring mechanisms to safeguard buyer interest.
**Risk Issues**

Based on the LCAPP Law and discussions with Board Staff and Counsel, LAI’s approach to resolving risk issues was based on the premise that the LCAPP was designed to place almost all risks on the generators with one notable exception, namely, the risk of market capacity prices set via annual BRAs. The LCAPP Law does not require operational or performance standards and is flexible concerning the timing of first capacity deliveries into the PJM market.

A threshold risk factor related to the possibility that generators selected with “winning” bids would not execute a SOCA. In order to dissuade winning generators from failing to enter into a SOCA, generators were required to submit Bid Security with their SOCP bids, in the form of an irrevocable standby LC or cash to be held in escrow, of $10/kW up to a maximum of $1 million.17

The LCAPP Law triggered responses from PJM, the PJM Independent Market Monitor (IMM), and generation companies concerned that the LCAPP Law will artificially depress Resource Clearing Prices (RCPs) set in the BRAs conducted each May by PJM. As discussed in the Minimum Offer Price Rule (MOPR) section of this Report, PJM and the PJM IMM jointly sent a letter to New Jersey Board President Solomon on December 3, 2010, expressing concern over LCAPP and suggesting that artificially low bids would be mitigated through the MOPR or a similar mechanism. A PJM generator group, referred to as P3, filed a complaint with the Federal Energy Regulatory Commission (FERC) on February 1, 2011 in which specific remedies to revise MOPR were proposed. On February 11, 2011, PJM submitted to FERC a Section 205 filing under the Federal Power Act. In this filing, PJM recommended a number of proposed MOPR revisions that would mitigate what was represented as artificially low capacity bid prices.18

In light of this additional risk, LAI re-examined the Proposed SOCA terms and conditions and recommended that LCAPP generators that fail to clear in a BRA not be unreasonably penalized. Through no fault of the generator, for example, PJM mitigation could reasonably cause the generator to delay construction until its bid clears the BRA. On the other hand, such a delay would deprive New Jersey ratepayers of economic, environmental, and community benefits. Working in consultation with Board Staff and Counsel, LAI determined that an unlimited delay would not be fair. Therefore, LAI suggested in the Proposed Form of SOCA that: (i) generators would have two years from the Awarded Commencement Date to achieve the date of first capacity deliveries, *i.e.*, the Commencement Date; (ii) once the Commencement Date is

---

17 The maximum Bid Security would be reached at 100 MW. Bid Security requirements and the Form of Bid LC were included in the Bid Submission Materials on the LCAPP web site and were addressed in the response to Questions 25, 30, 50, 53, 54, and 72. LAI informed eligible generators via email that cash to be held in escrow would be acceptable as Bid Security.

18 LAI reviewed the revisions proposed by PJM and P3, and while the P3 measures could be characterized as more aggressive than those proffered by PJM, LAI determined that if any of the proposed modifications to MOPR were approved by FERC, such modifications would constitute an additional and *previously unforeseen* risk that would materially threaten an LCAPP generator’s ability to clear in a BRA. LAI determined that the overarching uncertainty associated with the potential action(s) taken by FERC to revise the present MOPR was beyond the control of LCAPP bidders.
achieved, the SOCA remains in effect without payments to the generator for Delivery Years in which the generator failed to clear in the associated BRA; and, (iii) the amount of Construction Period Security that might have to be forfeited in the Event of Default and Termination be reduced to a maximum of $1 million. By significantly reducing the Construction Period Security, the Agent reasoned that the goals of the LCAPP Law would be encouraged by providing incentives to qualified generators to follow through with the development of worthwhile proposals in the LCAPP procurement in spite of the MOPR mitigation risks.

The EDC Proposed SOCA contained two provisions meant to protect themselves and ratepayers from risks in the event that rate recovery is denied and RPM is substantially modified, thereby impeding or preventing SOCA payments. The LCAPP Law expressly stated that “[n]either the Board nor any other governmental entity shall have the authority…to determine that the LCAPP charges or revenues to recover the LCAPP charges for such SOCA[s] are unjust or unreasonable.” Hence, LAI believed that the first EDC provision was unnecessary. Regarding modification to RPM, LAI reasoned that it would be preferable to have the EDCs and generators develop a replacement for the RCP, subject to Board approval, in order to avoid SOCA termination. LAI also suggested permitting mutually agreeable modifications to the SOCA, subject to Board approval.

The New Jersey Division of Rate Counsel (Rate Counsel) provided useful comments and suggestions regarding modifications to the Draft SOCA. LAI adopted Rate Counsel’s suggestion that the proposed facility be sufficiently defined to assure that any generator awarded a SOCA indeed constructs the proposed facility. However, LAI did not incorporate milestones and performance criteria in the SOCA. LAI also adopted Rate Counsel’s suggestions that: (i) capacity be measured as UCAP, the product that is purchased and sold in BRAs; (ii) the generator be required to competitively participate in the PJM energy and ancillary service (EAS) markets to assure that New Jersey ratepayers receive the benefits associated with the generator’s capacity; and (iii) some financial security be required in support of the generator’s contractual obligations.

Similar to Rate Counsel, CPV Shore, LLC recommended a “…reasonable and appropriate…” level of financial security be required. As explained above, LAI sought to strike a reasonable balance in setting separate amounts of financial security during the Construction Period ($10/kW with a cap of $1 million) and the Delivery Term ($25/kW with no maximum, declining pro rata over the Delivery Term). The MD PSC contract submitted by both Rate Counsel (as an

---

19 Any slippage would not delay the Conclusion Date, so that a generator with a 10-year SOCA that has its date of first capacity deliveries delayed for 2 years would effectively be left with an 8-year SOCA.
20 These changes, including reducing the Construction Period Security that would be forfeited in the Event of Default and Termination, were agreed to by Board Staff and Counsel.
21 LAI notes that the EDCs filed a Motion for Reconsideration with the Board, dated February 24, 2011, to amend the Board’s February 10, 2011 LCAPP Order regarding recovery of all SOCA costs through a non-bypassable, irrevocable charge.
22 UCAP takes the generator’s availability into account, e.g. a 100 MW generator with 90% availability would be able to sell 90 MW of UCAP.
23 See the response to Question 27.
example without modifications) and CPV (modified for LCAPP) contained various construction, operation, performance, and milestone requirements that LAI concluded were not appropriately includible in the SOCA, based on the LCAPP Law.

LS Power and Exelon provided ISDA-type SOCAs that had some useful terms and conditions that were adopted. Comments provided by Hess Corporation were also considered that addressed risk issues of failure to bid or clear in a BRA and potential modifications to RPM and the calculation of RCP. These risk issues are addressed throughout this section of the Report.

**Payment Issues**

The LCAPP Law requires SOCA payments based on the difference between the RCP and the generator’s SOCP. Based on suggestions from the six stakeholders who submitted Proposed SOCAs, LAI recommended that both prices should be expressed in UCAP and that SOCA payments be suspended in any Delivery Year when the generator’s UCAP does not clear the BRA. LAI reasoned that this second provision struck a fair and reasonable balance between unfairly penalizing generators for PJM mitigation and protecting ratepayers who would only be charged for capacity actually delivered.

The EDCs’ Proposed SOCA contained a Security Agreement that would protect the EDCs by attaching PJM payments to the generator if the RCP is greater than the SOCP. Lacking reciprocity, some stakeholders argued for the omission of this provision. In light of other financial security and contractual safeguards designed to protect ratepayers, LAI recommended eliminating the Security Agreement. Board Staff and Counsel concurred.

LAI notes that the EDCs have always had identical RCPs under RPM, starting with the first BRA for the 2007/08 Delivery Year. However, PJM considers each EDC’s service territory potentially as a separate Locational Deliverability Area (LDA). Therefore, RCPs could in fact vary for each EDC, and LAI had to consider how best to calculate the RCP in the event of price separation by LDA. LAI considered three options: (i) the RCP of the LDA in which the generator is located, (ii) the RCP of the EDC making the SOCA payment, or (iii) a weighted average “New Jersey RCP” of the four EDCs using their load ratios as weights. LAI decided that the fairest approach, consistent with the LCAPP Law’s intention of providing benefits to New Jersey, would be the third alternative where all ratepayers would make equal contributions consistent with the EDCs’ load ratio. LAI also provided for EDC load ratios to change over time, as calculated by PJM.

---

24 LAI alerted stakeholders that the SOCP would be based on UCAP in the response to Question 26.

25 As explained in Section 4.3 (Other Issues), LAI later decided to drop this calculation in favor of the RCP for the zone in which the generator is located.
4.2 Stakeholder Initial Comments on the Proposed Forms of SOCAs

The Order specified that Initial Comments on the Proposed SOCAs would be due by February 22, 2011. Six stakeholders filed Initial Comments, and in some cases included edits to the EDCs’ Proposed SOCA that was posted on February 14, 2011:

- NJ EDCs Comments and edited EDC SOCA
- Div. of Rate Counsel Comments and edited EDC SOCA
- LS Power Comments and edited EDC SOCA
- NRG Comments and edited EDC SOCA
- Hess Corp. Comments
- GenOn Energy Comments

The EDCs’ comments reiterated their position that failure to bid or clear in a BRA should be an Event of Default. LAI agreed that generators must be required to bid, but believed that ceasing payments if the generator failed to clear sufficiently protects ratepayer interests. In reaching this determination, LAI considered the prospect of these and other developers in New Jersey and elsewhere in PJM building new CC plants, among other technologies, strictly on the basis of merchant price signals, i.e., BRA prices and energy market clearing prices. In LAI’s judgment, the likelihood of a new generation facility entering the wholesale market absent the SOCA was low. Hence, the ratepayer protection afforded by the provision in the LCAPP Law requiring such resources to bid in the BRA was deemed sufficient. The EDCs also explained their position that denial of recovery, substantial modification of RPM, or a requirement to clear payments on an exchange be deemed termination events. While LAI did not agree with these positions put forward by the EDCs, LAI did in fact agree with the EDCs’ positions on a number of other issues, namely: (i) only cleared UCAP should be purchased under the SOCAs; (ii) a generator with a SOCA must offer the associated EAS into the PJM market; and, (iii) remedies must be made available to the EDCs if a generator fails to fulfill its obligations. Board Staff and Counsel agreed with LAI’s recommendations.

Rate Counsel suggested the following: (i) clearly identifying the proposed facility; (ii) prohibitions against withholding energy or ancillary services from the PJM market; (iii) filing an annual report with the Board; (iv) full recovery of costs; and, (v) failure to clear a BRA should not be an Event of Default or Termination. LAI agreed with these suggestions and therefore incorporated them in the SOCA. However, LAI did not adopt Rate Counsel’s suggested milestone and operational / performance requirements from the MD PSC contract, based on the rationale previously provided.

LS Power reiterated its belief that an ISDA-type form is more appropriate for the SOCA. While an ISDA-type form could be used, LAI remained convinced of the relative advantages associated with the EDCs’ form of contract. LS Power also provided useful comments and suggested

---

26 LAI was still in the process of preparing an initial draft SOCA that was not yet posted.
changes to the EDCs’ Proposed SOCA, including, but not limited to: (i) the proposed Security Agreement; (ii) the proposed requirement to clear in the BRAs; and, (iii) termination triggered by denial of rate recovery, modification of RPM, and execution of clearing requirements.

NRG submitted comments and specific edits to the EDCs’ Proposed SOCA highlighting NRG’s concerns regarding: (i) the allocation of risks, (ii) generator rights, (iii) termination payments, and (iv) financing-related provisions. LAI largely addressed these concerns through the changes described above that eliminated unreasonable generator requirements and balanced the competing interests between generators and the EDCs.

Hess submitted comments that focused on the uncertainty of clearing capacity in the BRA given anticipated MOPR mitigation. Hess suggested that SOCA payments be made based on the available capacity as opposed to the amount of capacity that clears the BRA. In LAI’s view, such a change would contravene the LCAPP Law and the Board’s Order. Hence, it was determined that the suspension of payments while allowing the SOCA to continue if the generator’s capacity does not clear in a Delivery Year constitutes a good balance between rival stakeholder interests. Hess also argued that the regulatory risks that were assigned to the generators under the EDCs’ Draft SOCA should be more equitably apportioned. Working in consultation with Board Staff and Counsel, LAI endeavored to do so.

GenOn indicated that it is a party to a Complaint filed in the U.S. District Court to bar the implementation of the LCAPP Law. GenOn commented on two issues: (i) the lack of any provision in the EDCs’ Proposed SOCA regarding potential MOPR mitigation of capacity bids and (ii) the lack of time to meaningfully participate in the LCAPP process. As explained above, LAI addressed MOPR mitigation by (i) providing for up to a two-year delay in first capacity deliveries, (ii) establishing a modest penalty in the form of Construction Period Security for termination prior to the Commencement Date, and (iii) permitting the SOCA to continue if the generator’s capacity does not clear after achieving the Commencement Date. Regarding GenOn’s second issue, lack of time, LAI recognized the time constraints, but could not alter the Order’s implementation schedule.

4.3 Stakeholder Reply Comments on Agent’s Draft SOCA (Version 1)

Based on the recommended positions described above, LAI posted the Agent’s Proposed Draft SOCA (version 1) on February 23, 2011. Key changes made to the EDCs’ draft can be summarized as follows:

- The EDCs’ Security Agreement was replaced with the Construction Period Security and Delivery Term Security.
- The time for generators to achieve the Commencement Date from six months (proposed by the EDCs) was extended to two years after the Awarded Commencement Date.
- If a generator failed to clear in a BRA prior to achieving the Commencement Date then that generator would be liable for the Construction Period Security of $10/kW up to a maximum of $1 million.
If a generator failed to clear after achieving the Commencement Date then any future failure to clear would cause SOCA payments to be suspended for that Delivery Year but the SOCA would continue in force, instead of triggering an Event of Default as in the EDC draft.

If RPM is eliminated or substantially modified, or if the RCP is no longer calculated, that would no longer be a Termination Event per the EDC draft but would instead require both parties to resolve the issue as a Dispute.

LAI alerted stakeholders on February 22, 2011 that the Proposed Draft SOCA would be posted on February 23, 2011, and that Reply Comments would be due on February 25, 2011 (per the Order) in responses to Questions 16, 18, 19, and 22. Eight stakeholders filed Reply Comments and submitted documents by February 25, 2011 as follows:

- NJ EDCs Comments, edited SOCA, and financial security documents
- LS Power Comments and edited SOCA
- CPV Shore, LLC Comments and edited SOCA
- Hess Corp. Comments and edited SOCA
- NRG Comments and edited SOCA
- Div. of Rate Counsel Comments
- Exelon Generation Comments
- NextEra Energy Comments

Working in close consultation with Board Staff and Counsel, LAI reviewed these comments and suggestions and prepared a detailed matrix of stakeholder positions on various SOCA provisions. On February 27, 2011, LAI consulted with Board Staff and Counsel in order to evaluate the relative positions of the various interested parties on key contract issues affecting the allocation of risk and reward between generators and the EDCs on behalf of New Jersey ratepayers.

The most important provisions, along with positions of the interested parties and LAI’s recommendations, were as follows:

**Capacity Clearing Requirement**

The EDCs argued that the LCAPP Law requires any SOCA to be terminated if a generator fails to clear in any BRA. Upon discussion with Board Staff and Counsel, LAI concluded that this was an unnecessarily strict interpretation that: (i) ignores the fact that ratepayers would bear no SOCP costs in any years that a generator fails to clear; (ii) would render projects unfinanceable in light of evolving PJM mitigation rules; and, (iii) would deprive ratepayers of future benefits by prematurely terminating SOCAs. LAI therefore maintained the previous position, as follows:

- In the event a generator with a signed SOCA bids in two successive BRAs and fails to clear (regardless of whether those bids were mitigated by PJM) and thus cannot achieve the Commencement Date within two years after the Awarded Commencement Date, this
would be an Event of Default under Section 7.1.7 (Failure to Achieve the Commencement Date) and the EDCs would be able to draw upon the generator’s Construction Period Security, which has a maximum amount of $1 million.

- In the event a project clears in a BRA and achieves the Commencement Date, and then bids in a succeeding BRA but fails to clear, SOCP payments would cease for that Delivery Year but the SOCA would continue in force.
- In either event, \textit{i.e.}, the generator fails to clear in a BRA prior to or after the Commencement Date, the Awarded Commencement Date would not be extended.

Board Staff and Counsel agreed with LAI that this was a reasonable solution that equitably balanced risk and reward between generators and the EDCs’ ratepayers.

**Calculation of UCAP Amount to be Bid**

LAI has sought to reasonably assure ratepayers of the full array of benefits from any project awarded a SOCA. Regarding the amount of UCAP that would be bid, cleared, and thus entitled to SOCP payments, LAI sought to encourage SOCA generators to provide as much UCAP as possible while also limiting the amount to the contract quantity. This way the LCAPP Law’s limit of 2,000 MW would not be exceeded. In consultation and agreement with Board Staff and Counsel, LAI revised the UCAP bid quantity in 2.3.3(b) to “no less than the Awarded Capacity Amount.” LAI noted that the definition of Available Capacity Amount (upon which SOCP payments are made) cannot be greater than the “Awarded Capacity Amount,” thereby protecting ratepayers by limiting total SOCP payments to the 2,000 MW limit.

**Energy and Ancillary Service Bid Prices**

LAI had suggested requiring SOCA generators to bid the EAS associated with the Available Capacity Amount into the relevant PJM markets at “the lowest allowable price under PJM’s Market Rules.” Some generators opposed this language, protesting that a strict interpretation might require them to sell these products at a loss, or that the SOCA provisions be restricted to capacity. In order to provide the generators more leeway and still assure that ratepayers receive the full amount of associated energy price and ancillary service benefits estimated in the bid evaluation process, LAI modified this bidding requirement to “lowest commercially reasonable price under PJM’s Market Rules” in Sections 2.3.3 (c) and (d) of the SOCA.\footnote{Additional clarity regarding this terminology was provided on the LCAPP website as Question 63.} Board Staff and Counsel agreed with this modification. LAI also made “Associated Energy” and “Associated Ancillary Services” defined SOCA terms.

**Rate Recovery**

The EDCs requested that a Condition Precedent be added “…that the Board has issued an order authorizing Utility to recover from ratepayers through a non-bypassable irrevocable charge all payments under this Agreement…” LAI anticipates that the Board will in fact issue such an order when it approves the SOCA awards, therefore this Condition Precedent was inserted with
agreement by Board Staff and Counsel, omitting other provisions suggested by the EDCs that were found to be superfluous.

Other Issues

- In addition to the EDCs’ annual reporting requirements, a provision was added that generators also submit annual reports to the Board certifying their compliance with SOCA bidding requirements. A provision requested by the EDCs clarifying that they have no monitoring or enforcement responsibilities was also added.

- The EDCs’ suggested language clarifying provisions regarding the Construction Period Security and Delivery Term Security was added.

- A bankruptcy provision was removed, as well as an assignment provision that would have interfered with generator financing.

- A Force Majeure clause suggested by generators that could be applied toward the Commencement Date was added.

- Some minor limitations to the Representations and Warranties suggested by a generator were added. Generators were not provided with a Termination for Convenience clause because the penalty for termination prior to the Commencement Date, the amount of Construction Period Security, is limited to $1 million and thus relatively small.

- Both the EDCs and generators suggested (for different reasons) that the weighted average New Jersey RCP not be utilized for payment calculations. LAI agreed and modified the SOCA to use the RCP for the generator’s location. The EDCs will continue to divide SOCA revenues or costs by load share ratio.

- LAI retained Illegality and Invalidity as Termination Events, and kept elimination or modification of RPM events as Disputes to be resolved by the parties. If any RPM or RCP dispute cannot be so resolved, the Resolution process was changed from arbitration to submittal to the Board.

- A provision that both parties cooperate to preserve the SOCA provisions in the event payments must be executed or cleared on an exchange, e.g., per Dodd-Frank legislation, was added. Contrary to the position set forth by the EDCs, LAI did not view such a requirement as reason to terminate the SOCA.

4.4 Stakeholder Supplemental Comments on Agent’s Draft SOCA (Version 2)

In order to provide stakeholders with as much opportunity as possible to provide comments and SOCA-related input to the drafting process, LAI posted a second version of the Proposed SOCA on February 28, 2011. Stakeholders largely reiterated previous comments with certain limited exceptions, and two generators submitted edited Agent Draft SOCAs.

The most important suggestion from LS Power was to add a Severability section that would seek to allow the SOCA to continue to the greatest extent possible in the event that any provision of the LCAPP Law was found to be invalid or unenforceable. LAI discussed this issue with Board Staff and Counsel and agreed to adopt the suggested language, but made any renegotiated SOCA
subject to Board approval. LS Power provided a letter from Union Bank, a subsidiary of Bank of Tokyo-Mitsubishi UFJ, which emphasized a number of financing considerations: (i) the importance of assuring revenue certainty, (ii) the ability of lenders to step in, (iii) default payments, (iv) generator liability, and (v) Force Majeure provisions. LAI considered LS Power’s suggestions, including the concerns expressed by Union Bank. In some cases repeating prior recommendations, LS Power made a number of other suggestions, as follows:

- Requested that the Conclusion Date be extended if Force Majeure delays the Commencement Date. LAI had previously discussed this issue with Board Staff and Counsel and maintained the position that the Conclusion Date would not be extended.
- Requested language concerning changes to RPM and the Dodd-Frank Act. LAI had previously discussed these issues with Board Staff and Counsel and believed that the existing SOCA provisions were reasonable and complied with the LCAPP Law.
- Requested changes to the Bankruptcy provisions consistent with Union Bank’s recommendation, which LAI agreed to accept.
- Requested that Illegality and Invalidity should not be Termination Events. LAI discussed this issue with Board Staff and Counsel and agreed that the Severability Clause would be a fair and reasonable compromise.
- Requested a different Early Termination Payment calculation that LAI and Board Staff and Counsel disputed.

NRG made many suggestions that it had previously made concerning termination rights, termination payments, and clearing requirements that LAI had previously discussed with Board Staff and Counsel disputed. In addition, NRG suggested termination payments due to an illegality or invalidity that were addressed by adding the Severability Clause as described above.

CPV Shore submitted comments that were intended, in CPV’s opinion, to better facilitate generator financing. CPV Shore suggested that generators could bid lower amounts of UCAP, but LAI believed this would relieve generators from achieving, and then maintaining, high availability levels. CPV Shore also suggested that forward-looking termination payments were not balanced, especially if the New Jersey Legislature could effectively cancel the SOCA at any time, and that the payments should be based on a PV estimate of future market capacity prices. LAI reasoned that CPV Shore’s suggested calculation would be too difficult to determine given financial uncertainties and market capacity price fluctuations.

Rate Counsel provided comments agreeing with the changes in the RCP definition, the removal of Suspension of Obligations, clarifying that the EDCs have no obligation to monitor generator performance, the provisions governing financial security, and replacing arbitration with Board resolution of disputes. LAI noted that Rate Counsel agreed with Agent on two important provisions:

- The interpretation that a SOCA (without payments) could continue if a generator fails to clear after the Commencement Date is reasonable and not precluded by the LCAPP Law.
- The EDCs are “sufficiently protected” with regard to rate recovery as a condition precedent and LAI adopted Rate Counsel’s recommended compromise language.
Rate Counsel made additional recommendations:

- Accept only a single SOCP value for all years, which LAI and Board Staff and Counsel believed was unnecessarily restrictive.
- Allow generators flexibility to bid UCAP less than the Awarded Capacity, which LAI and Board Staff and Counsel believed would allow generators to avoid SOCA provisions in order to receive higher market capacity prices when the RCP was greater than the SOCP.
- Require UCAP to be bid at the “lowest allowable price,” which was similar to the language of “lowest commercially reasonable price.”
- Require higher Construction Period Security, which LAI and Board Staff and Counsel believed would not be reasonable given the generator’s risk of MOPR mitigation.
- Require generators to submit an annual report, with which LAI agreed.
- Allow generators only a one-year delay to achieve the Commencement Date unless the Board granted an extension, which LAI believed was not materially different from the two-year grace period already proposed.

The EDCs also submitted comments that reiterated their previous points and claimed to identify “fundamental concerns” that the Agent’s Draft SOCA “fails in material respects to comply with…the LCAPP Law” as follows:

- Generators should be required to clear in order for the SOCA to remain in force. LAI and Board Staff and Counsel agreed that ceasing payments but leaving the SOCA in force is a reasonable compromise.
- The SOCA should ensure rate recovery for EDCs, and the conditions precedent language suggested by Rate Counsel was added.
- A generator should not be allowed to miss its Awarded Commencement Date, but LAI believed that a two-year delay should be permitted given the risk of MOPR mitigation.
- The EDCs should not have to monitor generator performance, and LAI added a corresponding provision for generators to report annually on their performance to the Board.

4.5 **Agent’s Final Proposed Form of SOCA**

LAI posted the Final Proposed Form of SOCA on the LCAPP website on March 1, 2011. In response, LAI received a question (posted as Question 69) to clarify the Final Proposed Form of SOCA’s provision for generators that failed to clear in the first two BRAs and thus would be in default under Section 7.1.7 Failure to Achieve the Commencement Date. In the response, it was stated that this would be an Event of Default in which case the EDCs could draw upon the Construction Period Security. The previous answer to a related question (Question 68) indicating that failure to clear a BRA after the generator achieves the Commencement Date would not be an Event of Default or Termination Event was also clarified.
LAI indicated early in the SOCA drafting process (per the response to Question 15 posted on February 18, 2011) that “…all winning generators will use the same form of SOCA…” Board Staff and Counsel agreed with Agent’s position. This position was reiterated in the response to Question 64 (posted March 4, 2011) that “[a]ny bid predicated on a substantive modification to the Final Proposed Form of SOCA dated March 1, 2011, will not be considered.” Having all generators adhere to the Final Proposed Form of SOCA would assure that all bids were based on the same apportionment of risk and reward as well as other terms and conditions. Allowing generators to substantially modify the Final Proposed Form of SOCA would alter the apportionment of risk and reward between buyer and seller, thereby rendering infeasible, if not impossible, Agent’s ability to fairly evaluate on an expedited basis the relative merits of competing bids. In the response to Question 64, respondents were notified that “[b]ids that identify technical corrections merely for consistency sake to the Final Proposed Form SOCA will be considered, however.” (emphasis added)

After the Final Proposed Form SOCA was posted, the EDCs submitted technical corrections that focused on correcting Section numbers that are referenced within the document. LAI recommends that the Board adopt those corrections. The corrected Final Form SOCA, inclusive of the EDCs’ technical corrections, is provided as Attachment 1 both in redline (Attachment 1A) and redline accepted (Attachment 1B) format.
5 PREQUALIFICATION EVALUATION PROCESS

The LCAPP Law required that one of the Agent’s tasks on behalf of the Board shall be:

“prequalifying eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date…”

This task was completed in two phases: (i) determination of eligibility under the LCAPP Law definitions; and, (ii) prequalification review of eligible bidders.

5.1 ELIGIBILITY SCREENING METHOD

In accordance with the LCAPP Law, an “[e]ligible generator” is “a developer of a base load or mid-merit electric power generation facility, including but not limited to, an on-site generation facility that qualifies as a capacity resource under PJM criteria and that commences construction after the effective date of [the LCAPP Law]”. Based on this definition, as well as the finding by the Legislature that, “[f]ostering and incentivizing the development of a limited program for new electric generation facilities will help ensure sufficient capacity to stabilize power prices…” (P.L.2011, c.9, Sec.1.i., emphasis added), the Agent identified those proposals that satisfied all three eligibility conditions:

• Proposed project must be a base load or mid-merit electric power generation facility;
• Proposed project must qualify as a capacity resource under PJM criteria; and
• Proposed project must be a new electric generation facility that did not begin construction on or before January 28, 2011.

Proposed generation projects that did not satisfy all three eligibility conditions were not promoted to the prequalification review phase.

5.2 PREQUALIFICATION REVIEW METHOD

All generators that were deemed to be eligible were subsequently evaluated with respect to the prequalification criteria identified in the LCAPP Law, requiring “a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date” (P.L.2011, c.9, Sec. 3.b.(2)). The Agent identified a set of factors that contribute to benefits or risks associated with each of the four LCAPP prequalification criteria. The Agent developed a matrix that defined the expectations and minimum requirements for each factor. For each eligible project, the Agent assigned a qualitative rating for each factor. The ratings were color-coded, as follows:

• Green – the project exceeds the minimum requirements or expectations
• Yellow – the project meets the minimum requirements or expectations
- Red – the project falls short of expectations (but is not critically deficient)
- Black – the project has significant deficiencies which could give rise to unacceptable risks for ratepayers or jeopardize the expected benefits

Each color rating was assigned a numerical value, and each factor was assigned a weighting. A weighted average score for each of the four LCAPP criteria was calculated based on the assigned ratings for each factor and the factor weightings. For each project, the percent of factors receiving a green or yellow rating was also calculated. Any project for which a black rating was assigned to any factor was considered to fail the prequalification phase. Projects failing the prequalification step of the due diligence were not carried forward to the quantitative analysis of net benefits phase.

In rating each project, LAI relied upon information provided in the Prequalification Application, supplemented by responses from bidders to Agent Question Sets and by publicly available information. In addition, the New Jersey Department of Environmental Protection (NJDEP), through the Office of Permit Coordination and Environmental Review, reviewed Prequalification Applications of all eligible projects. For projects that have already initiated the permitting process, NJDEP validated the permit status reported by each applicant. For all projects, NJDEP reviewed the Prequalification Application and information in NJDEP files, commented on the reasonableness of the permitting plan, and provided any other information in NJDEP files relevant to the feasibility of the project meeting the desired in-service date. The NJDEP’s review was not intended as a comprehensive analysis of permit requirements.

The following sections identify the factors contributing to each of the four LCAPP prequalification criteria, and define the color ratings for each factor. Note that this discussion is intended to define how the color ratings were to be assigned.

**Environmental Benefits**

LAI rated each eligible generator based on four factors contributing to the impact of the project on the environment. All factors related to this criterion were assessed on a qualitative basis.

**Air Emissions**

Projects were compared and rated based on the relative emissions of NO\textsubscript{x}, SO\textsubscript{2}, particulate matter (PM), mercury, and greenhouse gases, and the proposed emission control technologies. Gas-fired projects, with or without ultra-low sulfur distillate backup fuel, were considered to meet expectations and were rated yellow. Yellow-rated projects were also expected to propose, at a minimum, selective catalytic reduction (SCR) and other measures likely to meet NJDEP requirements for Best Available Control Technology (BACT) and/or Lowest Achievable Emission Rate (LAER).

---

28 All projects determined to be eligible were located in New Jersey, so the Agent did not contact environmental agencies in other states.
Projects with no direct emissions from fuel combustion and other renewable fuel projects were considered to exceed expectations and were rated green. Projects fired primarily by coal or oil, which would meet BACT, LAER, and/or Maximum Achievable Control Technology (MACT) requirements, but would produce greenhouse gas emissions at a rate significantly above gas-fired projects, were considered to be below expectations and were rated red. Other fossil-fired projects with no emission controls specified, or with emission control technologies unlikely to meet BACT, LAER, and/or MACT, as applicable, were considered to have significant deficiencies and were rated black.

**Condition of Site and Proximity to Sensitive Natural or Cultural Resources**

Projects were rated based upon the potential to positively or negatively impact environmental conditions on or adjacent to the project site and associated electric and gas rights-of-way. Projects located on a brownfield site or other impaired property, or would otherwise improve the condition of natural or cultural resources, were rated green. Projects that resulted in no significant impact to the project site, either positive or negative, were rated yellow. Yellow-rated projects included construction of new units on existing power plant sites. Projects that would be constructed on greenfield sites or adjacent to sensitive natural or cultural resources were rated red. Projects that would have a material, negative impact on sensitive natural or cultural resources were rated black.

**Water Use and Discharge**

Projects were rated based on proposed quantity, source, and discharge point of cooling and makeup water. Projects that proposed to minimize water use for cooling systems by including some type of evaporative cooling system were rated green or yellow. These projects were differentiated based on the source of the water supply. Green-rated projects proposed use of water reclaimed from a local water treatment facility and discharged via the municipal or county sewer authority. Yellow-rated projects proposed to use municipal water with limited discharge to surface water. Projects utilizing groundwater were also rated yellow provided that no incremental water withdrawal rights, relative to existing on-site use, is required. Wind projects requiring no cooling water were also rated as green. Projects that are anticipated to have potential limiting conditions on groundwater withdrawal rights or discharge permits were rated red. Projects proposing to use significant quantities of water for once-through cooling and likely to encounter significant obstacles obtaining water permits were rated black.

**Other Siting Issues**

Projects were rated based on additional environmental benefits or siting risks not captured in any other factor. Projects offering additional environmental benefits, such as beneficial re-use of waste, were rated green. Projects with no significant additional risks or benefits were rated yellow. Projects with other siting issues, such as environmental justice concerns, were rated red or black depending on whether these concerns could be mitigated.

**Economic Benefits**

Each eligible generator’s prequalification application was reviewed to ensure that information provided on the project description and operating data forms was adequate to allow economic
modeling of the proposed project. Eligible projects with adequate data in the original submission were awarded a green rating for this category. Those that met all requirements were awarded a yellow rating. If the necessary data were incomplete, but the data could be obtained from publicly available industry sources, a red rating was awarded. A black rating was assigned if the necessary data were incomplete and could not be derived from public industry sources. The quantitative assessment of economic benefits that drives the selection of bids is described in the Bid Evaluation section of this Report.

**Community Benefits**

The first qualitative factor in the area of community benefits was a determination of the level of demonstrated community support for the proposed generator. Active support by community and elected officials earned a green rating. Neutral community support earned a yellow rating. Mixed support and opposition from the community earned a red rating. Well-organized, demonstrated opposition combined with no evidence of support earned a black rating.

Financial contributions to the community, in the form of taxes or payments of lieu of taxes (PILOT), and grants or subsidies to the community were also evaluated as part of the demonstration of community benefits. For taxes / PILOT, ratings were determined by the expected level of contributions on a PV per MW basis, with above average contributions awarded a green rating, mid-range contributions awarded a yellow rating, and below average or unknown (to be determined) contributions awarded a red rating. In the grants / subsidies category, facilities with specific community improvements or subsidies were awarded a green rating, and facilities that did not specify community improvements or upgrades were awarded a yellow rating.

The final categories in the community benefits area were based on employment estimates, with four specific criteria: (1) construction period direct NJ employment; (2) operating period annual direct NJ employment; (3) construction period total employment; and (4) operating period annual total employment. All measures were evaluated on an FTE per MW basis, in order to fairly compare differently-sized generators. Green ratings in these four categories were awarded for above average FTE/MW ratios, yellow ratings were awarded for average FTE/MW ratios, and red ratings were awarded for below average FTE/MW ratios.

**Certainty of Meeting In-Service Date**

The Agent identified a set of factors which may potentially contribute to the risk of not achieving the proposed in-service date, thereby jeopardizing the value of benefits to ratepayers. These factors relate to the experience of the project sponsor, financeability and permitability of the

---

29 No black rating was applied to any of the community benefits factors, except for the factor relating to the level of community support or opposition.

30 Total employment includes direct, indirect and induced employment. Direct employment refers to construction or operations jobs at the generation facility. Indirect employment refers to jobs generated in businesses that supply goods and services to the generation facility. Induced employment refers to jobs created as a result of the directly and indirectly generated incomes being spent in the broader economy.
project, reasonableness of the development schedule and milestones, status of electric and gas interconnections, and fuel supply issues. A definition of the ratings for each of these factors is provided below.

**Sponsor / EPC Contractor Experience**

In the Prequalification Application, each project sponsor provided information regarding the relevant prior experience of the project team. Three relevant factors were evaluated: the experience of the project sponsor in successful development of similar projects, the experience of the engineering, procurement and construction (EPC) contractor, and any prior history of violations with respect to safety or environmental regulations during construction or operation of power plants.

In order to gauge the sponsor’s experience in developing power projects similar to those proposed in this LCAPP solicitation, LAI reviewed general information about the sponsor (including cover letters and project descriptions or narratives) and specific development experience of the sponsor staff. Projects received a green rating if the project sponsor has been the lead in the development, construction, and operation of a base load or mid-merit plant. The project received a yellow rating if the project sponsor has had a key role in the development, construction, or operation of a central station power plant. The project received a red rating if the project sponsor exhibited only limited experience in the development, construction, or operation of a central station power plant. A project received a black rating if the project sponsor had no relevant experience.

LAI also requested and evaluated the prior experience of the firms providing EPC services. Projects received a green rating if the selected EPC contractor has extensive experience with projects utilizing the proposed technology. The project received a yellow rating if the selected EPC contractor has some demonstrated experience with projects utilizing the proposed technology. The project received a red rating if the selected EPC contractor has limited experience with projects utilizing the proposed technology. A project received a black rating if the selected EPC contractor has no experience with projects utilizing the proposed technology.

The project team’s record of prior safety and/or environmental violations or felonies was also evaluated. Projects received a green rating for a record showing no violations of felonies in the past five years. The project received a yellow rating for a record showing only minor infractions or *de minimis* violations and no felonies in the past five years. The project received a red rating for a record showing one serious or willful violation or felony in the past five years. A project received a black rating for a record showing more than one serious or willful violation or felony in the past five years.

**Financial Strength / Financing Plan**

LAI evaluated the sponsors’ ability to finance the proposed projects based on their (or their guarantor’s) financial strength (including asset size and net current asset position), credit rating for unsecured long term senior debt, and ability to attract external funding as evidenced by any letters of interest / comfort provided by equity investors or lenders. In addition, LAI considered
the ability of the sponsor or guarantor to provide contingent equity in the event the project’s SOCA payments are temporarily halted.

If the sponsor or guarantor has balance sheet strength to provide equity and lenders issued strong comfort letters, the project received a green rating. If the sponsor or guarantor has moderate balance sheet strength to provide equity and lenders provided comfort letters with conditions, the project was rated yellow. If the sponsor or guarantor has weak balance sheet strength to provide equity and debt funding was conditional, the project received a red rating. If neither the sponsor nor guarantor has balance sheet strength to provide equity and no debt funding indicated, the project received a black rating.

LAI also assigned colors to each project based on the credit rating of the sponsor or guarantor. Projects received a green rating if the sponsor has unsecured long-term debt with investment grade rating and significant tangible net worth (TNW). Projects received a yellow rating if the guarantor has unsecured long-term debt with investment grade credit rating and significant TNW. Projects received a red rating if the sponsor or guarantor was below investment grade, but with a Moody’s, Fitch or Standard and Poors credit rating of at least “BB.” Projects with a sponsor or guarantor below a “BB” rating or not rated were scored as black.

Schedule Risk

All bidders were required to submit a proposed project schedule and milestones with their Prequalification Application. The Agent reviewed each project schedule for completeness and feasibility. Project schedules that were detailed, complete, and included feasible timelines for permitting, engineering, procurement, construction, and start-up, thereby providing a high degree of assurance that the project will meet the proposed in-service date, were rated green. Project schedules that included sufficient detail to demonstrate the feasibility of achieving the proposed in-service date were rated yellow. Project schedules that lacked detail, or indicated significant risk of delay, were rated red. If the project sponsor did not provide a project schedule, or if the development timelines imposed a high likelihood of not achieving the proposed in-service date, the project was rated black.

Permit Status

All bidders were required to provide a permitting plan with their Prequalification Application. The Agent evaluated the feasibility of achieving the proposed in-service date based on the current status of environmental permits and site remediation (if applicable), the proposed permitting milestones, and the completeness of the permitting plan.

Projects which have obtained all major permits, in particular, the Prevention of Significant Deterioration air permit, Title V air permit, Water Quality Certification, and New Jersey Pollutant Discharge Elimination System permit, and have obtained a “no further action” determination with respect to site remediation if applicable, were rated green since they represent
negligible schedule risk. Projects that have not yet initiated the permit process with the NJDEP, or have recently participated in a pre-application meeting with NJDEP, but propose an in-service date no earlier than May 31, 2015 were rated yellow. To receive a yellow rating, the Prequalification Application must indicate that major permit applications will be filed by 2Q2011 and allow for at least one year to obtain final permits. Projects which indicate a permit timeline that would require a more accelerated turnaround by NJDEP, or where site remediation is ongoing and may require modification to site development, received a red rating. Prequalification Applications which present a timeline that is infeasible with the proposed in-service date, or provide incomplete permit information, or will require extensive site remediation potentially incompatible with the site development schedule, were rated black.

Electric Interconnection Status

All bidders were required to provide information regarding the status of the electric interconnection with their Prequalification Application. LAI evaluated the feasibility of achieving the proposed in-service date and eligibility to participate in the first proposed BRA based on the current status of the PJM interconnection process and the interconnection milestones. For Planned Generation Capacity Resources to be eligible to participate in a BRA for a given Delivery Year, at a minimum, an executed System Impact Study (SIS) Agreement must be in place by April of the year in which the BRA takes place. In the review of the interconnection milestones for each Bidder, LAI used the date for the signing of the SIS Agreement as a critical milestone which must be met. For projects with completed interconnection studies, the Agent reviewed the posted studies on the PJM website to see if there was any evidence of any fatal flaws with the injection that might hamper the project’s development in the interconnection process.

With respect to electric interconnection, a project received a green rating if the project sponsor has essentially completed the interconnection process, representing negligible schedule risk. Green rated projects must have completed the PJM SIS process to the point of signing an Interconnection Service Agreement. Projects were rated yellow if they were well along the SIS process i.e. they had a signed SIS Agreement or the interconnection milestones facilitated timely signing of the SIS Agreement by the BRA deadline. Projects received a red rating if the project sponsor has not yet initiated the SIS process i.e., the project was in the Feasibility Study phase with no intention of signing an SIS Agreement. Projects received a black rating if an Interconnection Request had not yet been submitted and the project Sponsor’s interconnection plan was generally unresponsive regarding the interconnection milestones or the submitted interconnection milestones will not facilitate timely signing of an SIS Agreement by the BRA deadline.

31 Projects located on sites where groundwater remediation will continue during project development, but where such remediation is compatible with site development and project operation, would also be considered as representing negligible schedule risk.

32 For the 2013/2014 BRA the deadline was April 16th and for the 2014/2015 BRA the deadline is April 15th.
Gas Interconnection and Fuel Plan

The fuel supply criteria were evaluated separately for natural gas-fired and non-natural gas-fired plants. For natural gas-fired facilities, a green rating was assigned for a developed fuel supply plan that identifies a creditworthy fuel supplier(s) and experienced fuel manager while addressing all transportation, delivery and storage issues. Use of existing firm transportation entitlements or negotiations with a supplier/manager that has firm transportation entitlements on pipelines serving New Jersey were considered in a favorable light. A green rating also required an established right-of-way for local delivery, if applicable, and evidence of permits or local support for any on-site secondary fuel storage. LAI considered representations that secondary fuel would not be required to maintain requisite fuel assurance to the plant.

A yellow rating was assigned for a fuel supply plan that defines relevant supply, transportation, delivery, and storage issues, and identifies creditworthy fuel supplier(s)/manager that holds a portfolio of transportation arrangements including secondary firm entitlements that are available to the project. Right-of-way options for local fuel delivery are formulated and no significant risk factors have been identified with completion of these arrangements. A red rating was assigned for an inadequately developed fuel plan that does not fully define fuel supply and transportation issues, does not identify specific fuel suppliers or manager, and provides no specific evidence of transportation arrangements or plans to use non-firm transportation without evidence of permitting and local support for secondary fuel use and onsite storage. The red rating would also be applicable to a project for which significant barriers to the completion of local delivery arrangements have been identified. A black rating was assigned for an inadequate fuel plan that did not identify potential fuel suppliers, transportation and delivery arrangements, and did not provide an explanation of local delivery and interconnection plans.

For non-natural gas-fired plants, a green rating was assigned for having a complete fuel supply plan, including evidence of fully formulated supply, transportation, delivery and storage arrangements with a creditworthy supplier or manager, including defined commercial pricing provisions. In addition, the plan must provide demonstration that sufficient fuel resources or reserves are available to meet project fuel requirements over the term of the contract. A yellow fuel supply plan rating was assigned for projects with a complete fuel supply plan that do not have evidence of fuel supply, transportation, delivery and storage agreements in place or under negotiation. A red fuel supply plan rating was assigned for projects with poorly defined fuel arrangements, and a black rating was assigned to projects with no fuel supply plan identified.

Other Risk Factors

The Agent rated each project based on potential schedule risks not otherwise captured in any of the above factors. Projects were rated green if other potential schedule risks have been already addressed. Green-rated projects include those for which the EPC contractor has been identified and commercial terms are being negotiated. Projects were rated yellow if there were no other known schedule risks. Projects were rated red if there are potential other schedule risks, but such risks can be mitigated. Projects were rated black if there are other material projects risks which may not be mitigated, or if the sponsor has not yet achieved control of the project site through site ownership, a site lease, or an executed option on the site.
5.3 PREQUALIFICATION APPLICATIONS

Applicants submitted project information for prequalification in two ways: (1) by submitting Application Data Sheets and (2) by responding to Agent Question Sets.

Application Data Sheets

In keeping with the Board Order, the Application Data Sheets and Attachments thereto were posted to the LCAPP website on February 14, 2011. Applicants then had eight calendar days to respond, with submissions due at 5:00 pm EPT on February 22, 2011. The Application Data Sheets collected general project data and operating data, with Applicants completing either the dispatchable or variable energy worksheet, depending on the technology type. Additional qualitative and descriptive data was collected through the Application Data Sheet Attachments, which requested information on the facility’s sponsor, financing plan, permitting plan, fuel plan, operating plan, and community benefits. The information received through these forms was then evaluated using the method described above. For a complete list of the information requested on the Application Data Sheets and Attachments, please see the copy of the blank forms which were posted on the LCAPP website in Attachment 2 to this report.

Prequalification Applications were submitted for 34 generation projects prior to the 5:00 pm EPT deadline on February 22, 2011. A list of these projects, including sponsor, capacity (in UCAP), and location, is shown in Table 3.
Table 3. List of Applicants Submitting Prequalification Packages

<table>
<thead>
<tr>
<th>Applicant</th>
<th>Project Name</th>
<th>Location</th>
<th>UCAP (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bayonne Plant Holding, L.L.C.</td>
<td>Bayonne Expansion Project</td>
<td>Bayonne, NJ</td>
<td>38.00</td>
</tr>
<tr>
<td>Camden Plant Holding, L.L.C.</td>
<td>Camden Expansion Project</td>
<td>Camden, NJ</td>
<td>38.00</td>
</tr>
<tr>
<td>CPV Shore LLC</td>
<td>Woodbridge Energy Center</td>
<td>Woodbridge, NJ</td>
<td>690.00</td>
</tr>
<tr>
<td>EverPower Wind Holdings, Inc.</td>
<td>Liberty Wind Farm</td>
<td>Jersey City, NJ</td>
<td>2.69</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BR MUR Unit 1</td>
<td>Braceville, IL</td>
<td>16.61</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BR MUR Unit 2</td>
<td>Braceville, IL</td>
<td>15.66</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BY MUR Unit 1</td>
<td>Byron, IL</td>
<td>16.88</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BY MUR Unit 2</td>
<td>Byron, IL</td>
<td>15.88</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>DR Retrofit Unit 2</td>
<td>Morris, IL</td>
<td>12.88</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>DR Retrofit Unit 3</td>
<td>Morris, IL</td>
<td>13.72</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LI EPU Unit 1</td>
<td>Pottstown, PA</td>
<td>111.54</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LI EPU Unit 2</td>
<td>Pottstown, PA</td>
<td>111.37</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LI MUR Unit 2</td>
<td>Pottstown, PA</td>
<td>15.77</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LS EPU Unit 1</td>
<td>Marseilles, IL</td>
<td>125.49</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LS EPU Unit 2</td>
<td>Marseilles, IL</td>
<td>124.42</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LS MUR Unit 2</td>
<td>Marseilles, IL</td>
<td>15.80</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>Muddy Run</td>
<td>Holtwood, PA</td>
<td>1,063.08</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>QC Retrofit Unit 1</td>
<td>Cordova, IL</td>
<td>20.67</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>Salem Units 1 &amp; 2</td>
<td>Hancocks Bridge, NJ</td>
<td>954.15</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB Retrofit Unit 2</td>
<td>Delta, PA</td>
<td>1.50</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB EPU Unit 2</td>
<td>Delta, PA</td>
<td>51.91</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB Retrofit Unit 3</td>
<td>Delta, PA</td>
<td>1.50</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB EPU Unit 3</td>
<td>Delta, PA</td>
<td>51.92</td>
</tr>
<tr>
<td>Hess Corporation</td>
<td>Newark Energy Center</td>
<td>Newark, NJ</td>
<td>625.00</td>
</tr>
<tr>
<td>Middlesex Power Partners LLC</td>
<td>Sayreville Energy Center</td>
<td>Sayreville, NJ</td>
<td>430.00</td>
</tr>
<tr>
<td>New Jersey Power Development LLC</td>
<td>Old Bridge Clean Energy Center</td>
<td>Old Bridge, NJ</td>
<td>668.50</td>
</tr>
<tr>
<td>NRG Energy, Inc.</td>
<td>NRG Atlantic County Plasma Facility</td>
<td>Egg Harbor, NJ</td>
<td>31.00</td>
</tr>
<tr>
<td>PSEG</td>
<td>Peach Bottom 2 Extended Power Uprate</td>
<td>Delta, PA</td>
<td>51.90</td>
</tr>
<tr>
<td>PSEG</td>
<td>Peach Bottom 3 Extended Power Uprate</td>
<td>Delta, PA</td>
<td>51.90</td>
</tr>
<tr>
<td>PSEG Power LLC</td>
<td>Sewaren</td>
<td>Sewaren, NJ</td>
<td>596.94</td>
</tr>
<tr>
<td>PSEG Power LLC</td>
<td>Hudson</td>
<td>Jersey City, NJ</td>
<td>166.22</td>
</tr>
<tr>
<td>PSEG Power LLC</td>
<td>Kearny</td>
<td>Kearney, NJ</td>
<td>249.32</td>
</tr>
<tr>
<td>RC Cape May Holdings, LLC</td>
<td>BL England Generating Station</td>
<td>Beesley's Point, NJ</td>
<td>551.00</td>
</tr>
<tr>
<td>West Deptford Energy, LLC</td>
<td>West Deptford Energy Station</td>
<td>Paulsboro, NJ</td>
<td>620.00</td>
</tr>
</tbody>
</table>

---

33 Eligible generators had the option to ultimately bid less UCAP than they were prequalified for; therefore, the SOCA award quantities do not necessarily match the values in this table.
Requests for Additional Information

Following the initial review of the submitted prequalification materials, Agent Question Sets, or data requests, were developed and sent to all project sponsors who submitted Prequalification Applications. These data requests covered a variety of topics, seeking additional information or clarification of application responses in order to enable LAI to complete a thorough review of each project before making a determination regarding prequalification. Project sponsors were given three business days to respond to requests. In one case, the project sponsor did not receive the data request document so it was resent and a one day extension was granted. Multiple rounds of Question Sets were distributed:

- The first round of data requests were sent on February 24, 2011, to two projects that were immediately identified as ineligible generators to verify that the capacity was already in place and there was no capacity expansion investment planned.

- The second round of data requests were sent on February 27, 2011, to all 32 remaining projects and included questions regarding technical aspects of the projects, environmental issues, permitting, credit issues, fuel and emissions, construction progress, and community benefits. One project declined to respond and verified that it was withdrawing its application.

- On March 3, 2011, a data request was sent to one project to clarify the project sponsor and affiliates and another was sent to a second project regarding its Target Commercial Operation Date and related data.

- On March 6, 2011, the final sets of clarifying questions were sent to projects. Responses were due after the deadline for bidding. Two projects declined to respond as they had not submitted commercial proposals.

5.4 RESULTS OF ELIGIBILITY SCREENING

All projects that submitted complete Prequalification Applications were subjected to an eligibility screen based on the criteria summarized above. Of the 34 submitted projects, nine were determined to satisfy the eligibility conditions, and 25 were determined to not satisfy one or more of the eligibility conditions. Of the 25 ineligible facilities, 21 were eliminated because they were tied to existing generation units and therefore did not meet the condition of being a new generation facility. Four projects were eliminated because they were categorized as peaking units, rather than exhibiting the base load or mid-merit operating regime required by the LCAPP Law. Bidders were notified on March 3, 2011, of their eligibility status. The lists of eligible and ineligible generators are shown in Table 4 and Table 5, respectively.
### Table 4. Eligible Generators

<table>
<thead>
<tr>
<th>Applicant</th>
<th>Project Name</th>
<th>UCAP (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPV Shore LLC</td>
<td>Woodbridge Energy Center</td>
<td>690.00</td>
</tr>
<tr>
<td>EverPower Wind Holdings, Inc.</td>
<td>Liberty Wind Farm</td>
<td>2.69</td>
</tr>
<tr>
<td>Hess Corporation</td>
<td>Newark Energy Center</td>
<td>625.00</td>
</tr>
<tr>
<td>Middlesex Power Partners LLC</td>
<td>Sayreville Energy Center</td>
<td>430.00</td>
</tr>
<tr>
<td>New Jersey Power Development LLC</td>
<td>Old Bridge Clean Energy Center</td>
<td>668.50</td>
</tr>
<tr>
<td>NRG Energy, Inc.</td>
<td>NRG Atlantic County Plasma Facility</td>
<td>31.00</td>
</tr>
<tr>
<td>PSEG Power LLC</td>
<td>Sewaren</td>
<td>596.94</td>
</tr>
<tr>
<td>RC Cape May Holdings, LLC</td>
<td>BL England Generating Station</td>
<td>551.00</td>
</tr>
<tr>
<td>West Deptford Energy, LLC</td>
<td>West Deptford Energy Station</td>
<td>620.00</td>
</tr>
</tbody>
</table>

### Table 5. Ineligible Generators

<table>
<thead>
<tr>
<th>Applicant</th>
<th>Project Name</th>
<th>UCAP (MW)</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bayonne Plant Holding, L.L.C.</td>
<td>Bayonne Expansion Project</td>
<td>38.00</td>
<td>Peaker</td>
</tr>
<tr>
<td>Camden Plant Holding, L.L.C.</td>
<td>Camden Expansion Project</td>
<td>38.00</td>
<td>Peaker</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BR MUR Unit 1</td>
<td>16.61</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BR MUR Unit 2</td>
<td>15.66</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BY MUR Unit 1</td>
<td>16.88</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>BY MUR Unit 2</td>
<td>15.88</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>DR Retrofit Unit 2</td>
<td>12.88</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>DR Retrofit Unit 3</td>
<td>13.72</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LI EPU Unit 1</td>
<td>111.54</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LI EPU Unit 2</td>
<td>111.37</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LI MUR Unit 2</td>
<td>15.77</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LS EPU Unit 1</td>
<td>125.49</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LS EPU Unit 2</td>
<td>124.42</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>LS MUR Unit 2</td>
<td>15.80</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>Muddy Run</td>
<td>1,063.08</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>QC Retrofit Unit 1</td>
<td>20.67</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>Salem Units 1 &amp; 2</td>
<td>954.15</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB Retrofit Unit 2</td>
<td>1.50</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB EPU Unit 2</td>
<td>51.91</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB Retrofit Unit 3</td>
<td>1.50</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>Exelon Generation Company, LLC</td>
<td>PB EPU Unit 3</td>
<td>51.92</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>PSEG</td>
<td>Peach Bottom 2 Extended Power Uprate</td>
<td>51.90</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>PSEG</td>
<td>Peach Bottom 3 Extended Power Uprate</td>
<td>51.90</td>
<td>Existing Facility</td>
</tr>
<tr>
<td>PSEG Power LLC</td>
<td>Hudson</td>
<td>166.22</td>
<td>Peaker</td>
</tr>
<tr>
<td>PSEG Power LLC</td>
<td>Kearny</td>
<td>249.32</td>
<td>Peaker</td>
</tr>
</tbody>
</table>
5.5 RESULTS OF PREQUALIFICATION REVIEW

LAI evaluated the nine eligible generation facilities in accordance with the prequalification methodology described above. The Agent relied on information contained in the Prequalification Applications, responses to Agent Question Sets, feedback from the NJDEP, and publicly available information. Responses to the final Agent Question Sets were received on March 9, 2011, therefore, the prequalification review could not be finalized until after the SOCP Bids were received on March 7, 2011. No bidders were disqualified either before or after the SOCP bids were submitted.

The results of the prequalification review for the nine eligible generation facilities are shown in Table 6. Sponsors of projects listed as “Withdrawn” either declined to submit responses to an Agent Question Set and notified the Agent that they had decided not to continue the process, and/or did not submit SOCP Bids on March 7, 2011. Prequalification review of the three withdrawn projects was not completed.

All six remaining projects were deemed to be prequalified. All six projects received a red rating for at least one individual factor. None of the red scores indicated an obstacle to development or a material risk to ratepayers. Red scores indicated undefined aspects of the project that will be addressed through further project development, or less desirable site conditions that are counterbalanced by other project benefits. On a weighted average basis, all of the prequalified projects received ratings of yellow or green for all of the four criteria: environmental benefits, community benefits, economic benefits, and demonstration of reasonable certainty of meeting the desired in-service date. No prequalified project received a black score for any factor.

<table>
<thead>
<tr>
<th>Applicant</th>
<th>Project Name</th>
<th>UCAP (MW)</th>
<th>Prequalification Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPV Shore LLC</td>
<td>Woodbridge Energy Center</td>
<td>690.00</td>
<td>Prequalified</td>
</tr>
<tr>
<td>EverPower Wind Holdings, Inc.</td>
<td>Liberty Wind Farm</td>
<td>2.69</td>
<td>Withdrawn</td>
</tr>
<tr>
<td>Hess Corporation</td>
<td>Newark Energy Center</td>
<td>625.00</td>
<td>Prequalified</td>
</tr>
<tr>
<td>Middlesex Power Partners LLC</td>
<td>Sayreville Energy Center</td>
<td>430.00</td>
<td>Prequalified</td>
</tr>
<tr>
<td>New Jersey Power Development LLC</td>
<td>Old Bridge Clean Energy Center</td>
<td>668.50</td>
<td>Prequalified</td>
</tr>
<tr>
<td>NRG Energy, Inc.</td>
<td>NRG Atlantic County Plasma Facility</td>
<td>31.00</td>
<td>Withdrawn</td>
</tr>
<tr>
<td>PSEG Power LLC</td>
<td>Sewaren</td>
<td>596.94</td>
<td>Withdrawn</td>
</tr>
<tr>
<td>RC Cape May Holdings, LLC</td>
<td>BL England Generating Station</td>
<td>551.00</td>
<td>Prequalified</td>
</tr>
<tr>
<td>West Deptford Energy, LLC</td>
<td>West Deptford Energy Station</td>
<td>620.00</td>
<td>Prequalified</td>
</tr>
</tbody>
</table>
6 BID EVALUATION METHOD

The third phase of the selection process was evaluation of commercial proposals, which included pricing and term.

6.1 BID FORM AND SUPPORTING MATERIALS

Bidding instructions were posted to the LCAPP website on February 23, 2011. Applicants were instructed to submit three components in order to complete the bid package for a proposed generating facility, as described in the following sections.

SOCP Bid Form

The SOCP Bid Form was set up as an Excel file that was protected such that bidders could only enter data into selected cells. Bidders were instructed to complete a Bid Form for each Pricing Option they elected to offer into the LCAPP. The Bid Form required that bidders enter a term (not to exceed 15 years) for each Pricing Option. Bidders were then given the option to specify either a constant price for the entire selected term, or a different price for each year of the selected term.

Bid Security

Bidders were required to submit Bid Security to act as assurance that they would execute SOCAs with the EDCs if so Ordered by the Board. A standard LC that has been used in other procurements managed by the Agent was used, with modifications specific to the LCAPP. Bidders were given the option of submitting cash held in escrow as Bid Security in lieu of LCs, but no bidders selected this option.

Officer Certification Form

Bidders were required to submit a notarized copy of the Officer Certification Form attesting to the following certifications:

- The undersigned is an officer of the Applicant with legal authority to sign contracts and bind the Applicant to its Standard Offer Capacity Price and all other Bid Information submitted in the New Jersey Long-Term Capacity Agreement Pilot Program, pursuant to New Jersey Board of Public Utilities Order in Docket No. EO11010026, dated February 10, 2011 (“SOCP and Bid Information”).

- The undersigned certifies that the SOCP and Bid Information submitted by the Applicant on the Standard Offer Capacity Price Bid Form to Levitan & Associates, Inc., as Agent,

34 The Officer Certification Form can be found on the LCAPP website at: http://www.nj-lcapp.com/Documents/Officer_Certification_Form.doc
shall be firm, irrevocable, and binding upon the Applicant until April 30, 2011, 5:00 PM EPT.

- The undersigned certifies that all information provided in Applicant’s Pre-Qualification Package and in subsequent communications with the Agent regarding the capacity offered by Applicant in the New Jersey Long-Term Capacity Pilot Program remains correct and valid.

- If the Applicant is notified that it has been chosen to enter into a Standard Offer Capacity Agreements ("SOCA") with each of the New Jersey Electric Distribution Companies ("EDCs"), and if the New Jersey Board of Public Utilities approves the form of the SOCA reflecting the SOCP and Bid Information, then the undersigned certifies that a duly authorized representative of the Applicant will execute the four SOCAs within thirty (30) days of being notified that the New Jersey Board of Public Utilities has approved the form of the SOCA.

- The Applicant is providing four Bid Letters of Credit to be drawn on by the four New Jersey EDCs in the event that the Applicant is selected as a winning bidder and fails to execute the SOCAs within thirty (30) days of being notified that the New Jersey Board of Public Utilities has approved the form of the SOCA.

6.2 SUMMARY OF BIDS RECEIVED

Of the nine generators determined to be eligible following the initial screening process, bids were received from six:

- BL England Generation Station
- Newark Energy Center
- Old Bridge Clean Energy Center
- Sayreville Energy Center
- West Deptford Energy Station
- Woodbridge Energy Center

A total of 18 pricing options were submitted by the six facilities. Of these, six pricing options were conditioned on substantial modifications to the Final Proposed Form of SOCA and were therefore eliminated for non-conformance:

- One bidder submitted four pricing options for its project, all of which were predicated on modifications that included deleting the Termination Events of Illegality and Invalidity (Sections 8.1.1. and 8.1.2) and inserting a substantially different calculation for Events of Default. Consistent with the explicit instructions to bidders, LAI rejected these four bids. Board Staff and Counsel concurred.

- Another bidder submitted four pricing options for its project, two of which were predicated on a substantial modification that would permit the generator to terminate the SOCA without penalty prior to the BRA associated with the second Delivery Year.
Consistent with the explicit instructions to bidders and with the agreement of Board Staff and Counsel, LAI rejected the two pricing options that included substantial SOCA modifications.

- Two additional pricing options from a third bidder were eliminated because they were based on a facility configuration that had not been submitted during the prequalification phase. One additional pricing option from this bidder was eliminated because it was for an incomplete project.

6.3 **GROSS SOCA COST**

Gross SOCA cost is the PV of the products of annual SOCP, the offered capacity and days per year over the proposed SOCA term. The annual values are discounted to the beginning of the 2014-2015 Delivery Year. This is a measure of the firm financial commitment of New Jersey ratepayers under the SOCAs, and can be expressed in unit terms (PV of $/kW) or total terms (PV $).

6.4 **RCP CREDIT**

RCP Credit is the present value of the products of the forecasted annual RCP, the offered capacity, and days per year over the SOCA term. The annual values are discounted to the beginning of the 2014-15 Delivery Year. This is a measure of the direct return to New Jersey ratepayers under the SOCAs as compensation for commitment to the firm SOCP string. RCP Credit can be expressed in unit terms (PV of $/kW) or total terms (PV $).

6.5 **NET SOCA COST**

Net SOCA Cost is calculated as Gross SOCA Cost less RCP Credit and represents the estimated PV of contract transaction payments under a proposed SOCA, as defined in Section 4.1 of the SOCA form. It consists of the PV over delivery years 2015 through 2032 of estimated net payments between the EDCs and the generator under the terms of the SOCA. Net SOCA Cost is a function of the proposed SOCP stream, the beginning Delivery Year, the number of Delivery Years in the proposed SOCA term, the proposed SOCA Capacity, and the series of future RCPs determined by LAI based on the market simulation and financial models used by Agent to represent the BRA. Net SOCA Cost is calculated as the PV of a stream of annual net costs applicable to each Delivery Year of the SOCA term. The cost each year is determined as the product of 365 days per year, the SOCA capacity in MW, and the difference (positive or negative) between the SOCP and forecasted RCP (expressed in $/MW-day) for each year.

6.6 **ECONOMIC BENEFITS TO NEW JERSEY RATEPAYERS**

**PJM Electricity Market**

Wholesale energy prices in PJM are referred to as Locational Marginal Prices (LMPs) because energy prices across the market area vary by location. LMPs tend to be highest during summer months when demand is highest due to air conditioning load and lowest during the spring and
fall when demand is relatively low. Sometimes LMPs are high during the winter because of the high seasonal cost associated with delivered natural gas, one of the primary determinants of wholesale power prices in New Jersey. From a locational perspective, LMPs tend to be highest in urban areas due to transmission constraints and the need to rely on more expensive peaking generation plants to meet demand and to satisfy grid reliability objectives.

PJM administers the Day-Ahead Market (DAM) and the Real-Time Market (RTM). Both clear on an hourly basis. Prices in the DAM are calculated the day before delivery and are based on one day ahead load forecasts and generator bids. Prices in the RTM are established the day of delivery and are based on actual system conditions.\(^{35}\) In PJM, the wide majority of energy transactions are cleared in the DAM.

For every hour, active generators submit bids into the energy market. These bids are sorted by PJM and formed into a “bid stack.” The highest bids are from the least efficient resources, in particular, peaking plants. The lowest bids are from base load units such as coal or nuclear facilities. “Mid-merit” facilities such as CC plants typically submit bids in the DAM or the RTM that are in-between those submitted by base load plants and peakers. PJM selects the lowest bids that are required to meet demand for a given hour. Of the units selected, the one with the highest bid sets the clearing price with adjustments for losses and congestion, \(i.e.,\) LMP. All units that clear the market receive their nodal LMP regardless of each unit’s respective bid price.

Generators are paid based on their location in PJM by node, at which prices for every hour are calculated for both the DAM and RTM. Load pays a zonal price, which is the load-weighted average price of all the generation nodes within a given zone. Zones are typically defined by utility service territories. There are 18 zones in PJM. For New Jersey ratepayers, the LMP zones of relevance are Atlantic City Electric Company (AECO), Rockland Electric Company (RECO), Jersey Central Power and Light Company (JCPL), and Public Service Electric and Gas Company (PSEG).

Historically, prices within the four New Jersey LMP zones have been nearly identical. Figure 7 shows average daily on-peak clearing prices for each of the four New Jersey zones since the beginning of 2008.\(^{36}\)

---

\(^{35}\) The purpose of the RTM is to cover unanticipated system requirements associated with variances in the conditions that had been expected when DAM prices were established. For example, if load is greater the day of delivery than had been expected on the previous day when the DAM prices were set, load would be required to purchase additional energy in the RTM.

\(^{36}\) On-Peak hours are the sixteen hours of each weekday beginning with the eighth and ending with the twenty-third hour of each day, excluding holidays.
LMPs in PJM tend to be higher to the North and East than to the West and South. Wholesale prices in New Jersey are among the highest in the region. Figure 8, below, compares the JCPL LMP to the PJM load-weighted average LMP for the last several years.
There are multiple reasons why prices in New Jersey are high, but primary among them is the make-up of New Jersey’s indigenous generation fleet. The state is heavily dependent on relatively inefficient gas turbines (GTs), which often set the LMP. Furthermore, delivered gas prices in New Jersey are relatively high compared to the rest of PJM. New Jersey’s dependence on less efficient GTs creates an opportunity for the addition of more efficient resources to lower energy prices in and around New Jersey, while recouping margin from energy sales.37

Reliability Pricing Model

Under the RPM, PJM conducts an annual BRA that establishes annual market-based RCPs for LDAs three years in advance of the actual Delivery Year. PJM also conducts Incremental Auctions to cover required variances in supply or demand that develop after a BRA, but prior to the relevant delivery year; however, the results of the Incremental Auctions do not affect payments under the SOCA.

Each EDC service territory can be treated as an LDA if it is expected to “bind”, i.e., if it does not have sufficient generation and import capability to meet its capacity requirements. Those requirements are determined by the forecasted peak load net of any demand-side reductions. Thus an LDA that is expected to be constrained could have a higher RCP compared to other LDAs. PJM calculates the Capacity Emergency Transfer Limit (CETL), the amount of capacity an LDA can import, and the Capacity Emergency Transfer Objective (CETO), the amount of capacity an LDA would be required to import, to determine if an LDA will be constrained.

LDAs are “nested” in PJM, so that the EDC LDAs are part of the Eastern Mid-Atlantic Area Council (EMAAC) LDA, which is part of the Mid-Atlantic Area Council (MAAC) LDA, which itself is part of the entire Regional Transmission Organization (RTO). Thus, New Jersey EDCs could have RCPs set by their individual LDA, by EMAAC, by MAAC, or by the RTO, depending on the balance between local demand, local capacity resources, and transmission capacity. Generally, PJM determines whether to model an LDA based on the ratio between its CETL and CETO. CETL is the amount of capacity an LDA can import under emergency conditions, and CETO is the amount of capacity an LDA would be required to import under emergency conditions after consideration of its peak demand and capacity resources.38 Under PJM rules, EMAAC and MAAC will always be modeled as separate LDAs. The RCPs could be above (but never below) the RTO RCP.

RCPs are set at the intersection of the supply curves comprised of resource bids and demand curve referred to as a Variable Resource Requirement (VRR) curve based on the forecasted peak load. The height of the VRR curve is determined by the Net Cost of New Entry (Net CONE). PJM estimates Gross CONE – the levelized capital cost and fixed operating expense for a

37 As indicated by Figure 7, units selected by PJM to run in New Jersey in any hour receive similar LMPs differentiated somewhat by loss factors and congestion. A CC plant has much lower variable operating costs than a gas turbine. While a CC plant would receive the benefit of an LMP set by a less efficient resource, the addition of one or more CC plants in New Jersey is expected to reduce LMPs, thereby benefiting load throughout New Jersey.
38 PJM models an LDA if its CETL / CETO ratio falls below 1.15, or if it previously exhibited price separation within the last three BRAs.
A postulated gas turbine unit – by location prior to each BRA. Net CONE is equal to Gross CONE, adjusted for inflation and an offset for EAS. Its position along the x-axis is calculated as the reliability requirement for the relevant LDA (or RTO) multiplied by the 1.0 plus the Installed Reserve Margin (15% in the case of PJM) plus 1%, divided by 1.0 plus the IRM. The VRR curve to be used in the 2014/15 BRA for the RTO is illustrated in Figure 9.

![Figure 9. Variable Resource Requirement Curve](image)

**New Jersey Resource Clearing Prices**

The first RPM BRA was held in April 2007 for capacity commitments starting on June 1, 2007, the beginning of the 2007/08 Delivery Year. Since then, six additional auctions have been held, with a wide range of price outcomes for ratepayers in New Jersey. New Jersey EDCs have always paid the same RCPs (with adjustments for Capacity Transfer Rights allocated by PJM to the EDCs). As illustrated in Figure 10 below, the New Jersey RCP was set by the EMAAC LDA (the red line) in most Delivery Years, but from 2009/10 to 2011/12 the New Jersey RCP was set by the MAAC LDA (the purple line). PJM has approved a number of large, high voltage backbone transmission lines to alleviate these constraints, which should cause the RCPs to converge over time.

---

39 In last year’s BRA, the EMAAC and MAAC RCPs were higher than the RTO because there was relatively more capacity outside of EMAAC and MAAC but there was insufficient transmission to deliver that capacity to those LDAs.
Figure 10. Historical RPM Clearing Prices

Energy Market Model

The long-term forecast of energy prices in PJM was performed using the MarketSym multi-area chronological dispatch simulation model. This section of the report highlights key elements that were customized specifically for this proceeding to reflect market dynamics across PJM and neighboring market areas.

Load Forecast

LAI utilized load shape data based on the most recent available ISO load data forecasts, including the PJM 2011 Load Forecast Report. A downward revision to the economic outlook for the PJM area has resulted in lower peak and energy forecasts compared to PJM’s previous forecast. Summer peak load growth for PJM RTO is projected to average 1.3% per year over the next ten years, and 1.1% over the following 15 years. Winter peak load growth for PJM RTO is projected to average 1.1% per year over the next ten years and 0.9% over the following 15 years.

Generation Unit Retirements

Events at the Fukushima Daiichi Nuclear Power Station in Japan may have repercussions with respect to the relicensing or early retirement of nuclear units in New Jersey, elsewhere in PJM, and throughout neighboring market areas. Consistent with the Consent Order, LAI assumed the retirement of Oyster Creek in New Jersey in 2019. The only other nuclear retirement in PJM included in the retirement analysis is Dominion Energy’s Surrey units. Importantly, LAI’s model development was completed in February 2011, and therefore reflects the status of nuclear

---

units known prior to the March 11, 2011 earthquake. The commercial and safety implications associated with the Nuclear Regulatory Commission’s and the Department of Energy’s reviews of U.S. nuclear reactor performance and integrity is outside the scope of this LCAPP procurement.

Older fossil-fuel plants in PJM are coming under increasing economic pressure due to age, low energy prices, and environmental regulations. Energy and capacity revenues may be barely sufficient to cover ongoing operation and maintenance costs for aging plants. In many cases, the decision has been made to retire the plant or unit. Table 7 lists recent plant deactivations and pending deactivation requests in PJM as of January 20, 2011.
Table 7. Recent and Pending PJM Fossil Fuel Plant Deactivations

<table>
<thead>
<tr>
<th>Unit</th>
<th>Capacity</th>
<th>Age (Years)</th>
<th>Projected or Actual Deactivation Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Howard M. Down (Vineland) Unit 8</td>
<td>11.0</td>
<td>53</td>
<td>6/5/2009</td>
</tr>
<tr>
<td>Indian River 2</td>
<td>89.0</td>
<td>48</td>
<td>5/1/2010</td>
</tr>
<tr>
<td>Hunlock 3</td>
<td>45.0</td>
<td>48</td>
<td>6/1/2010</td>
</tr>
<tr>
<td>North Branch</td>
<td>74.0</td>
<td>18</td>
<td>8/1/2010</td>
</tr>
<tr>
<td>Howard M. Down (Vineland) Unit 9</td>
<td>17.0</td>
<td>49</td>
<td>8/28/2010</td>
</tr>
<tr>
<td>INGENCO Richmond Plant</td>
<td>3.0</td>
<td>18</td>
<td>8/31/2010</td>
</tr>
<tr>
<td>Hall Branch (aka Altavista)</td>
<td>63.0</td>
<td>19</td>
<td>10/13/2010</td>
</tr>
<tr>
<td>Gorsuch</td>
<td>18.9</td>
<td>59</td>
<td>11/11/2010</td>
</tr>
<tr>
<td>Baleville Landfill</td>
<td>3.8</td>
<td>9</td>
<td>12/22/2010</td>
</tr>
<tr>
<td>Kingsland Landfill</td>
<td>2.8</td>
<td>11</td>
<td>12/22/2010</td>
</tr>
<tr>
<td>Will County 1</td>
<td>151.0</td>
<td>55</td>
<td>12/30/2010</td>
</tr>
<tr>
<td>Will County 2</td>
<td>148.0</td>
<td>55</td>
<td>12/30/2010</td>
</tr>
<tr>
<td>Hudson 1</td>
<td>383.0</td>
<td>39</td>
<td>9/1/2012</td>
</tr>
<tr>
<td>Chesapeake 8</td>
<td>17.5</td>
<td>41</td>
<td>4/19/2011</td>
</tr>
<tr>
<td>Chesapeake 9</td>
<td>16.9</td>
<td>41</td>
<td>4/19/2011</td>
</tr>
<tr>
<td>Chesapeake 10</td>
<td>16.9</td>
<td>41</td>
<td>4/19/2011</td>
</tr>
<tr>
<td>Kitty Hawk GT1</td>
<td>18.0</td>
<td>39</td>
<td>4/19/2011</td>
</tr>
<tr>
<td>Kitty Hawk GT2</td>
<td>16.0</td>
<td>39</td>
<td>4/19/2011</td>
</tr>
<tr>
<td>Indian River 1</td>
<td>90.0</td>
<td>50</td>
<td>5/1/2011</td>
</tr>
<tr>
<td>Cromby 1</td>
<td>144.0</td>
<td>55</td>
<td>5/31/2011</td>
</tr>
<tr>
<td>Eddystone 1</td>
<td>279.0</td>
<td>49</td>
<td>5/31/2011</td>
</tr>
<tr>
<td>Cromby Diesel</td>
<td>2.7</td>
<td>43</td>
<td>5/31/2011</td>
</tr>
<tr>
<td>Sporn 5</td>
<td>440.0</td>
<td>49</td>
<td>6/1/2011</td>
</tr>
<tr>
<td>Cromby 2</td>
<td>201.0</td>
<td>54</td>
<td>12/31/2011</td>
</tr>
<tr>
<td>Benning 15</td>
<td>275.0</td>
<td>39</td>
<td>5/31/2012</td>
</tr>
<tr>
<td>Benning 16</td>
<td>275.0</td>
<td>35</td>
<td>5/31/2012</td>
</tr>
<tr>
<td>Buzzard Point East Banks 1, 2, 4-8</td>
<td>112.0</td>
<td>39</td>
<td>5/31/2012</td>
</tr>
<tr>
<td>Buzzard Point West Banks 1-8</td>
<td>128.0</td>
<td>39</td>
<td>5/31/2012</td>
</tr>
<tr>
<td>Eddystone 2</td>
<td>309.0</td>
<td>49</td>
<td>6/1/2012</td>
</tr>
<tr>
<td>Kearny 10</td>
<td>122.0</td>
<td>39</td>
<td>6/1/2012</td>
</tr>
<tr>
<td>Kearny 11</td>
<td>128.0</td>
<td>40</td>
<td>6/1/2012</td>
</tr>
<tr>
<td>Chesapeake 7</td>
<td>16.0</td>
<td>40</td>
<td>7/28/2012</td>
</tr>
<tr>
<td>Ingenco Petersburg Plant</td>
<td>2.9</td>
<td>20</td>
<td>5/31/2013</td>
</tr>
<tr>
<td>Kearny 9</td>
<td>21.0</td>
<td>43</td>
<td>6/1/2013</td>
</tr>
<tr>
<td>Indian River 3</td>
<td>169.7</td>
<td>40</td>
<td>12/31/2013</td>
</tr>
</tbody>
</table>

In addition to the retirements in Table 7, LAI has assumed that an additional 9,315 MW of coal-fired capacity will be retired in PJM between 2014 and 2019. This consists almost entirely of small units (less than 200 MW) that are currently more than 40 years old and face a combination

---

41 The recent deactivations include those plants deactivated since January 1, 2009, which is the date of the existing generator list in PJM’s most recent EIA 411 filing.
of environmental capital expenditures and/or tighter margins on energy sales. LAI has also assumed that 2,259 MW of oil/gas-fired plants will be retired during the same time frame.

The retirement of older fossil-fuel plants is likely to accelerate due to a number of environmental regulations proposed by the U.S. Environmental Protection Agency (EPA). These regulations could require that expensive retrofits to be installed in order to continue operating the facility. In many cases, the cost of the retrofit cannot be justified on the basis of going-forward earnings by the plant owner, and a decision will be made to retire the plant instead of undertaking the required retrofits.

Regulations that are expected to have the greatest impact on plant retirement in the near future are as follows:

- **Section 316(b) of the Clean Water Act** – Regulates cooling water intake structures. Revised rulemaking to be issued shortly may require elimination of once-through cooling and its replacement with closed-loop cooling systems.
- **Title I of the Clean Air Act** – Provides regulatory authority for National Emission Standards for Hazardous Air Pollutants for the electric power industry. In a proposed rulemaking issued on March 16, 2011, EPA set MACT standards for mercury, acid gases, heavy metals and organics for coal- and oil-fired power plants. This may require the retrofit of significant additional emissions control equipment.
- **Clean Air Transport Rule (CATR)** – Proposed program issued July 6, 2010 would sharply reduce emissions of sulfur dioxide and nitrogen oxide from power plants in 31 states in the eastern half of the U.S. and the District of Columbia. The need to retrofit for additional emissions controls is likely depending on which of three different program options is adopted.
- **Coal Combustion Residuals** – Pending regulations under the Resource Conservation and Recovery Act will reduce available options for and increase the cost of coal ash disposal.

At this time, none of these regulations is final. However, all of them are expected to be finalized by mid 2012 and then fully implemented by 2018. The impact of these rules on existing generating facilities is uncertain until the rules are finalized, but it will be significant. Several recent studies have examined the potential impact of these rules. The North American Electric Reliability Corporation (NERC) projects a loss of between 46 GW and 76 GW due to derates and retirements of coal- and oil/gas-fired steam units nationwide by 2018, with the variation depending on whether the final rules can be considered moderate or strict. The Brattle Group, looking only at coal-fired plants, projected the retirement of between 50 GW and 65 GW by

---

42 Note that New Jersey, as well as other states in PJM, including Maryland and Delaware, has already promulgated regulations limiting mercury emissions from coal-fired power plants that are at least as stringent as the proposed EPA limits.

IFC International also looked only at coal-fired plants, and included the potential impact from federal regulation of greenhouse gas emissions under a cap-and-trade program. ICF found that 75 GW of coal-fired generation is at risk of retirement by 2018, driven primarily by the high cost of installation for scrubbers and fabric filters to meet MACT requirements. Credit Suisse considered only the impact of clean air regulations (MACT and CATR) on coal-fired plants in the U.S. Based on the plant sizes and existing emissions controls, Credit Suisse identified 60 GW at risk in their base case, with high and low cases of 100 GW and 35 GW, respectively.

Focusing attention on PJM, Brattle Group concluded that 12 GW to 19 GW of coal-fired generation was at risk of retirement by 2020. Credit Suisse found that 25% of coal-fired capacity in PJM (19,553 MW) lacked both scrubbers and SCR. Much of that capacity is at larger plants, where economies of scale will help justify the necessary environmental capital expenditure to keep the plant operational. But roughly half of that capacity, 9,841 MW, is at plants with capacities of 300 MW or less, nearly all of which are between 40 and 60 years old. The economic conditions at these plants are much more likely to favor a decision to retire. In addition, 4,865 MW is at small coal-fired plants that currently have SCR but lack scrubbers. These plants will also be at significant risk of retirement. In its base case, Credit Suisse assumed that 12,274 MW of coal-fired generation in PJM would retire between 2013 and 2017.

The results of the NERC study are not directly comparable to those of Credit Suisse or Brattle Group. NERC organized its results according to reliability areas. PJM is located within the Reliability First Corporation (RFC) area, which includes portions of several Midwestern states that are outside PJM. Furthermore, Dominion, a member of PJM, is located in the SERC Reliability Corporation (SERC) area. The NERC study includes Dominion in the Virginia and the Carolinas (VACAR) sub-region of SERC. Since PJM has nearly 80 GW of coal-fired capacity compared to 97 GW for RFC as a whole, the impact reported for RFC in the NERC study will be broadly indicative of the expected impact on PJM.

Looking first at the coal-fired plants, NERC determined that the combined impact of the four environmental regulation areas listed above would be 5,250 MW for the moderate case (1,965 MW of derates and 3,285 MW of retirements.) The corresponding value for the strict case was 13,154 MW (2,266 MW of derates and 10,888 MW of retirements.) These values are in addition to the retirements that have already been committed or announced. Within the VACAR sub-region of SERC, the impacts are 2,111 MW for the moderate case (453 MW derates and 1,658 MW retirements) and 5,126 MW for the strict case (492 MW derates and 4,634 MW retirements.)

As mentioned above, the NERC study also looked at the impact of environmental regulations on oil/gas-fired steam units. The results of NERC’s analysis was identical for both the moderate

and strict cases, with a projected impact of 4,563 MW in RFC (all retirements) and 431 MW in VACAR (23 MW derate and 408 MW retirements.)

Transmission

The transmission infrastructure into and within New Jersey affects the energy and capacity prices of relevance in the determination of Net SOCA cost and total net benefits for New Jersey’s ratepayers. Model inputs reflected the existing transmission infrastructure and upgrades that will likely improve transfer capabilities into the EMAAC and MAAC zones. For simulation purposes, LAI included the following high-voltage backbone transmission projects that have received PJM Board approval.

Trans-Allegheny Interstate Line (TrAIL)

TrAIL is a 500-kV transmission line that will extend 218 miles from the 502 Junction substation in PA to the Loudon substation in VA. Based on the PJM analysis of 2011, the TrAIL project is required to resolve reliability criteria violations starting June 1, 2011. The project is currently under construction and LAI’s simulation analysis assumes an in-service date of June 1, 2011.

Susquehanna-Roseland

Susquehanna-Roseland is a 130-mile, 500-kV transmission line, with a path from Susquehanna (PA) to Lackawanna (PA) to Hopatcong (NJ) to Roseland (NJ). The project’s developing Transmission Owners are PPL, responsible for the Pennsylvania portion, and PSE&G, responsible for the New Jersey portion. The project will provide a high voltage link between north-central PA and EMAAC. Based on the PJM 2012 analysis, the Susquehanna-to-Roseland project is required to resolve reliability criteria violations starting June 1, 2012; however, the project’s in-service date has been subject to permitting delays. As a result, the Roseland-to-Hopatcong portion of the Project is currently expected to be in-service by June 2014. The remainder of the Project is anticipated to be completed by June 2015. LAI’s simulation analysis assumes that the complete project will be in-service by 2015.

Potomac Appalachian Transmission Highline (PATH)

In its current configuration, PATH will consist of a 276-mile 765-kV transmission line to be constructed from the existing Amos substation in West Virginia to the proposed Kemptown substation in northern Maryland. The need for PATH was first identified as part of PJM’s 2007 Regional Transmission Expansion Plan (RTEP). At that time PATH’s planned in-service date was June 2012; since then the project’s configuration has changed and the in-service date has also changed a number of times, most recently to June 2015 as part of the 2010 RTEP studies. Because of a lower than expected 2011 load forecast, PJM has since suspended the project and so it is expected that its in-service date will be delayed by several years.

Mid-Atlantic Power Pathway (MAPP)

The MAPP project, as currently designed, will consist of 152 miles of new overhead, underground, and underwater transmission lines and cables that will connect southern MD with the Delmarva Peninsula. The need for MAPP was first identified as part of the 2007 PJM RTEP,
with an original planned in-service date in June 2013. The configuration and in-service were subsequently revised, and in 2010 PJM re-affirmed the need for the revised project with a delayed in-service date of June 1, 2015. As with PATH, it is also expected that the in-service date of MAPP will be delayed.

**Hudson Transmission Project**

LAI did not include the Hudson Transmission Project (HTP) in the transmission topology linking PJM with the New York Independent System Operator (NYISO). The reason HTP was not included in the resource mix is due to uncertainty about the project’s status, in particular, the existence of executed transmission contracts between HTP and entitlement holders, *i.e.*, the New York Power Authority (NYPA) and Consolidated Edison Co. (Con Ed).\(^\text{47}\) HTP is a 660-MW (net capacity) HVDC controllable transmission line that is designed to run approximately 8 miles from the Bergen Substation in Ridgefield, New Jersey to the Con Ed West 49th Street Substation in New York City. HTP is designed to include a back-to-back AC/DC/AC converter station in Ridgefield, New Jersey that provides controllability and scheduling capability to the flow of energy between PJM and the NYISO.\(^\text{48}\)

Several years ago NYPA selected HTP to provide transmission capacity through its open and competitive RFP process. Pursuant to NYPA’s RFP process, HTP and NYPA have reached agreement, subject to NYPA Board approval, on a long-term contract under which NYPA would purchase 75% of HTP’s transmission capacity for 20 years. Hudson has announced an in-service date of summer 2013, but there have been a number of project delays over the years.

HTP’s Interconnection Service Agreement facilitates the interconnection of 320 MW of Firm Transmission Withdrawal Rights (FTWRs) and 353 MW of Non-Firm Transmission Withdrawal Rights. To support its FTWR allotment from PJM, HTP is responsible for funding $172 million in network upgrades to the PJM transmission system.

**Renewable Portfolio Standards**

The majority of states comprising PJM have Renewable Portfolio Standard (RPS) requirements. LAI’s simulation model incorporates the expected build-out of renewable resources across the study area, as described below. The current Class I (or Tier 1) requirements in each state are shown in Table 8. In addition to the Class I requirements, New Jersey, DC, Illinois, Maryland, Ohio, and Pennsylvania also have a solar RPS. In some states it is a carve-out of the Class I requirement, and in some states it is incremental to the Class I requirement.

---

\(^{47}\) To the extent HTP is commercialized, the cable loading factor between New Jersey and midtown Manhattan may put upward pressure on LMPs in New Jersey, a market scenario that has not be tested by Agent in the derivation of net energy benefits ascribable to the recommended SOCA portfolio.

\(^{48}\) The AC transmission line coming out of the HVDC back-to-back converter station is to be installed underground and under the Hudson River.
Our capacity expansion projection for renewable resources across PJM will be in accordance with the following assumptions:

- A portion of the aggregate PJM Class I requirement will continue to be met by existing biomass and landfill gas (methane), but no new biomass or landfill gas resources will be added except to offset the declining production of existing resources.
- Solar photovoltaic resources are built out in each zone such that each state’s respective solar carve-out is fully met, with a two-year delay.
- Wind resources in the PJM interconnection queue that are listed as “partially in service” or “under construction” were added to the model at the start of the calendar year following the expected in-service date stated in the queue.
- Generic off-shore wind projects are modeled with generation ramp-up beginning in 2017; early years are based on “known” project capacity under contract and state legislative mandates.
- All of the incremental renewable capacity to meet the aggregate PJM RPS Class I requirement in each year will consist of generic on-shore wind projects; the incremental
resources needed to maintain this percentage are added in zones in proportion to the relative distribution in the PJM queue.

- Power production data for onshore and offshore wind plants is based on available meteorological data for each specific region. 49

**Demand-Side Management**

Goal No. 1 established in the 2008 New Jersey Energy Master Plan (EMP) is maximizing energy conservation and energy efficiency (EE). More specifically, the EMP requires reducing energy consumption at least 20% by 2020, which would yield electricity savings of nearly 20,000 GWh per year. 50 Goal No. 2 of the EMP is to reduce peak electricity demand by 5,700 MW by 2020. 51 Similarly aggressive demand-side management programs exist in other states of the region, e.g., in Maryland. 52

LAI notes that demand-side participation in the PJM Capacity Market has increased dramatically since the inception of RPM in the 2007/08 Delivery Year. Demand-side participation includes active demand response (DR) resources and, starting from the 2012/13 Delivery Year, EE resources. Table 9 below illustrates DR and EE participation by zone in the recent BRA for the 2013/14 Delivery Year.

---

49 Most wind data used by LAI is from the National Oceanic and Atmospheric Administration’s National Data Buoy Center or other public sources of wind data. Some wind data are from special studies such as the EWITS study and actual plant performance data.

50 The 2008 New Jersey Energy Master Plan at 11.

51 Id.

52 Maryland’s EmPOWER initiative, otherwise referred to as the “15 by 15” initiative.
Table 9. Demand Response and Energy Efficiency Resources in the 2013/14 BRA (UCAP)

<table>
<thead>
<tr>
<th>Constrained LDA</th>
<th>Zone</th>
<th>Offered MW</th>
<th></th>
<th>Cleared MW</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>DR</td>
<td>EE</td>
<td>Total</td>
<td>DR</td>
</tr>
<tr>
<td>EMAAC</td>
<td>AECO</td>
<td>122.1</td>
<td>3.1</td>
<td>125.2</td>
<td>122.1</td>
</tr>
<tr>
<td>EMAAC</td>
<td>DPL</td>
<td>245.7</td>
<td>3.4</td>
<td>249.1</td>
<td>245.7</td>
</tr>
<tr>
<td>EMAAC</td>
<td>JCPL</td>
<td>283.7</td>
<td>4.4</td>
<td>288.1</td>
<td>283.7</td>
</tr>
<tr>
<td>EMAAC</td>
<td>PECO</td>
<td>658.2</td>
<td>5.6</td>
<td>663.8</td>
<td>658.2</td>
</tr>
<tr>
<td>EMAAC</td>
<td>PSEG</td>
<td>1,119.2</td>
<td>7.4</td>
<td>1,126.6</td>
<td>1,119.2</td>
</tr>
<tr>
<td>EMAAC</td>
<td>RECO</td>
<td>32.4</td>
<td>0.0</td>
<td>32.4</td>
<td>32.4</td>
</tr>
<tr>
<td>EMAAC Sub Total</td>
<td></td>
<td>2,461.3</td>
<td>23.9</td>
<td>2,485.2</td>
<td>2,461.3</td>
</tr>
<tr>
<td>PEPCO</td>
<td>PEPCO</td>
<td>547.3</td>
<td>35.8</td>
<td>583.1</td>
<td>547.3</td>
</tr>
<tr>
<td>MAAC</td>
<td>BGE</td>
<td>1,102.5</td>
<td>74.8</td>
<td>1,177.3</td>
<td>1,102.5</td>
</tr>
<tr>
<td>MAAC</td>
<td>METED</td>
<td>318.1</td>
<td>7.2</td>
<td>325.3</td>
<td>318.1</td>
</tr>
<tr>
<td>MAAC</td>
<td>Penelec</td>
<td>420.7</td>
<td>8.0</td>
<td>428.7</td>
<td>420.7</td>
</tr>
<tr>
<td>MAAC</td>
<td>PPL</td>
<td>1,021.2</td>
<td>2.3</td>
<td>1,023.5</td>
<td>1,021.2</td>
</tr>
<tr>
<td>MAAC Sub Total</td>
<td></td>
<td>5,871.1</td>
<td>152.0</td>
<td>6,023.1</td>
<td>5,871.1</td>
</tr>
<tr>
<td>RTO</td>
<td>AEP</td>
<td>1,513.1</td>
<td>5.9</td>
<td>1,519.0</td>
<td>823.9</td>
</tr>
<tr>
<td>RTO</td>
<td>APS</td>
<td>721.9</td>
<td>3.7</td>
<td>725.6</td>
<td>523.2</td>
</tr>
<tr>
<td>RTO</td>
<td>ATSI</td>
<td>1,384.8</td>
<td>3.0</td>
<td>1,387.8</td>
<td>394.3</td>
</tr>
<tr>
<td>RTO</td>
<td>COMED</td>
<td>1,521.1</td>
<td>513.7</td>
<td>2,034.8</td>
<td>851.9</td>
</tr>
<tr>
<td>RTO</td>
<td>DAY</td>
<td>277.1</td>
<td>17.2</td>
<td>294.3</td>
<td>42.5</td>
</tr>
<tr>
<td>RTO</td>
<td>DOM</td>
<td>1,435</td>
<td>60.6</td>
<td>1,495.6</td>
<td>632.7</td>
</tr>
<tr>
<td>RTO</td>
<td>DUQ</td>
<td>228.6</td>
<td>0.7</td>
<td>229.3</td>
<td>142.3</td>
</tr>
<tr>
<td>Grand Total</td>
<td></td>
<td>1,2952.7</td>
<td>756.8</td>
<td>13,709.5</td>
<td>9,281.9</td>
</tr>
</tbody>
</table>

DR and EE are part of the Reference Case. As a starting point in the modeling assumptions, LAI relied on the results of the 2013/14 BRA. From 2014 to 2020, a phased demand side management case which is a combination of the energy efficiency / conservation and active DR was included. The penetration level of EE and DR resources is consistent with the objectives of the New Jersey EMP, and other states in EMAAC that have sought to implement aggressive DR and EE programs. From 2020 to 2030, the level of incremental DR and EE penetration will be adequate to offset a significant share of the load and energy consumption growth in EMAAC.

EMAAC Consolidation

As previously discussed, there is little day-ahead or real-time energy price separation across the individual load zones within EMAAC. Hence, LAI has modeled EMAAC as a single zone. LAI has verified this by comparing average LMPs for the individual EMAAC load zones against the simple average LMP for PJM as a whole. The data in Table 10 indicates that LMPs in the individual load zones within EMAAC were tightly clustered relative to MAAC LMPs for the Pennsylvania Electric Company (Penelec) and PPL Electric Utilities Corporation (PPL) zones. The color-coding demonstrates the clustering on EMAAC LMPs relative to the average PJM price, and is adjusted from 2008 to 2009 to reflect the tightened LMPs in 2009 as LMPs generally declined. LAI’s treatment of modeling EMAAC as a single zone will significantly
facilitate quantification of energy price effects over the study horizon by eliminating the need to estimate transfer limits dynamics among the individual EMAAC zones. Figure 7 and Figure 8 in Section 6.6 show graphical representations of these relationships.

### Table 10. EDC Energy Prices Relative to PJM Average Energy Price

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM Average LMP</td>
<td>$66.12</td>
<td>$66.40</td>
<td>$37.00</td>
<td>$37.08</td>
</tr>
<tr>
<td>EMAAC EDCs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AECO</td>
<td>119%</td>
<td>122%</td>
<td>112%</td>
<td>110%</td>
</tr>
<tr>
<td>DPL</td>
<td>118%</td>
<td>116%</td>
<td>113%</td>
<td>111%</td>
</tr>
<tr>
<td>JCPL</td>
<td>121%</td>
<td>119%</td>
<td>112%</td>
<td>110%</td>
</tr>
<tr>
<td>PECO</td>
<td>115%</td>
<td>113%</td>
<td>110%</td>
<td>108%</td>
</tr>
<tr>
<td>PSEG</td>
<td>121%</td>
<td>119%</td>
<td>113%</td>
<td>111%</td>
</tr>
<tr>
<td>RECO</td>
<td>118%</td>
<td>117%</td>
<td>111%</td>
<td>109%</td>
</tr>
<tr>
<td>Other MAAC EDCs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Penelec</td>
<td>98%</td>
<td>95%</td>
<td>100%</td>
<td>99%</td>
</tr>
<tr>
<td>PPL</td>
<td>112%</td>
<td>110%</td>
<td>108%</td>
<td>106%</td>
</tr>
</tbody>
</table>

### Capacity Market Model

In order to forecast RCPs, LAI utilized a proprietary model that replicates the functionality of the RPM. The model generates a VRR curve for each study year based on a forecast of Net CONE and peak load. PJM’s Net CONE calculations for the 2014/15 BRA in EMAAC, MAAC, and RTO are shown in Table 11, below. The last line expresses Net CONE in terms of $/MW-day of UCAP, the standard PJM convention, assuming a system average equivalent availability of 93.75%.

---

53 UCAP takes into account the rating of any supply-side or demand-side capacity resource under PJM rules, adjusted for unit availability. UCAP is sold by capacity resources and purchased by both EDCs and load serving entities.
Table 11. Net CONE Calculations for 2014/15 Base Residual Auction
($/MW-yr unless otherwise noted)

<table>
<thead>
<tr>
<th></th>
<th>EMAAC</th>
<th>MAAC</th>
<th>RTO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross CONE</td>
<td>$138,646</td>
<td>$128,226</td>
<td>$128,226</td>
</tr>
<tr>
<td>Net Energy Revenue Offset</td>
<td>$42,339</td>
<td>$43,247</td>
<td>$8,920</td>
</tr>
<tr>
<td>Ancillary Services Offset</td>
<td>$2,199</td>
<td>$2,199</td>
<td>$2,199</td>
</tr>
<tr>
<td>Net CONE</td>
<td>$94,108</td>
<td>$82,780</td>
<td>$117,107</td>
</tr>
<tr>
<td>($/MW-Day, UCAP)</td>
<td>$275.02</td>
<td>$241.91</td>
<td>$342.23</td>
</tr>
</tbody>
</table>

LAI has no reason to expect RCPs for the New Jersey EDCs to diverge in the future. Hence, LAI estimated the changes in CETO and CETL for EMAAC and MAAC in order to ascertain which LDAs would set the RCPs for the New Jersey EDCs as well as to locate the VRR curves along the x-axis. LAI expects that the PJM backbone transmission lines discussed in the section above on Transmission inputs to the energy market model will increase CETL for both EMAAC and MAAC over the forecast horizon.

Once LAI established the VRR curves for each year of the study period, RCPs were forecasted based on the supply of capacity resources available with the LDAs. For example, the RTO cleared in the 2013/14 BRA with a significant amount of excess capacity – above a 20% reserve margin. Simply put, there was more capacity than needed to meet reliability requirements, which resulted in a low RCP. In subsequent years, as that excess supply is reduced by load growth and retirements, the model forecasts higher RCPs.

Reference Case

Over the course of the Reference Case forecast, the amount of capacity available to meet reliability requirements in PJM increases by about 23,000 MW. This amount is net of the retirements described in above. About 12,000 MW is assumed to be retired between 2014 and 2019. An additional 4,000 MW retires after 2029. Between 2014/15 and 2033/34, about 39,000 MW of new capacity is added, representing a net increase of about 23,000 MW across the market area.

The majority of new resources added to the supply mix over the forecast period are simple-cycle GTs, along with some DR/EE, wind and CC plants. Solar, biomass, and other resource types are also added to the generation mix in comparatively small amounts. Figure 11, below, shows the addition of GT, wind, CC, DR/EE resources over the study period.
Resources are not added to the generation mix in uniform increments. Rather, they are periodically added in large blocks in response to the perception of tightening market conditions. For example, excess supply and reserve margins in PJM are projected to decrease through 2017 due to load growth and plant retirements. As a result, LAI assumed the market adds several thousand MW of new supply, primarily GTs, as indicated in Figure 11. Consistent with actions taken or contemplated by states, power authorities, and vertically integrated utilities, LAI believes that there is a societal preference for a cushion of extra capacity over the forecast period rather than a steady state equilibrium condition where total installed capacity exactly meets the installed capability requirement, no more, no less. The forecasted length of the supply curve therefore reflects periodic large blocks of new generation additions over the forecast period that occasionally leads to excess generation supplies.

Offsetting this increase in capacity is load growth of approximately 25,000 MW over the study period, so that the PJM capacity market periodically tightens and RCPs rise toward Net CONE. While RCPs may converge on Net CONE, in LAI’s view of the wholesale pricing dynamic, the BRA price effect does not converge on Net CONE for long. As a result, a “saw-tooth” pattern characterizes the LAI forecast of RCPs as market equilibrium is transient, followed by a drop in prices as new capacity is commercialized. This trend is repeated over the forecast period.

Our projection of Net CONE for the Reference Case is based on the 2014/15 Net CONE calculated by PJM, which LAI has escalated by 0.9% each year, one-half of LAI’s general inflation rate of 1.8%. The lower escalation rate is used to account for expected technology progress over the forecast period, thereby reducing the cost of constructing a GT peaking plant over the study period in real terms.
Under this scenario, New Jersey RCPs will be set by the RTO for most years in the study period. However, LAI expects that 2014/15 RCPs will be set by MAAC because that LDA will be “tighter” with higher RCPs than EMAAC or the RTO. LAI also expects the 2018/19 RCPs to be set by EMAAC, as that LDA will temporarily be tighter than MAAC or the RTO. The RTO sets New Jersey RCPs in the remainder of the years, primarily because GTs are expected to earn much lower net energy revenues, leading to higher Net CONE values, consistent with Table 11. Thus, when all three LDAs are at or near equilibrium conditions – thereby clearing at or near Net CONE – the RTO will set the New Jersey RCP.54

Our forecast of New Jersey RCPs is shown in Figure 12.

**Figure 12. New Jersey Resource Clearing Price Forecast**

![Graph showing New Jersey Resource Clearing Price Forecast](image)

6.7 **MINIMUM OFFER PRICE RULE**

**Procedural Matters and Chronology**

On December 3, 2010, Messrs. Ott of PJM and Bowring of Monitoring Analytics, PJM’s IMM, sent a letter to President Solomon of the Board, expressing concern over the LCAPP Law, particularly the requirement that selected capacity resources must offer and clear in the BRA conducted annually under the RPM rules. Concern was expressed over the possibility that capacity awarded under the LCAPP may participate in the May 2011 BRA for Delivery Year

---

54 Under FERC-approved rules, RCPs in an LDA cannot be lower than RCPs for the RTO as a whole.
2014/15. Messrs. Ott and Bowring noted that the primary purpose of the RPM MOPR was to prevent new capacity resources from submitting “…uneconomic offers based on the receipt of out of market payments to artificially depress RPM auction prices.” PJM concluded that the LCAPP Law’s requirement to clear the BRA equated to requiring SOCA capacity resources to submit a zero (or equivalent) bid offer. According to PJM and the IMM, such an offer would violate the intent of the MOPR, and thus they “…will assert that MOPR should apply to this situation,” in which case the selected capacity resource would be at risk of not clearing in the BRA.

As previously discussed, on February 1, 2011, P3 filed a Complaint and Request for Clarification requesting fast track processing at FERC, Docket EL11-20-000. According to P3, MOPR is flawed because it can allow uneconomic entry of subsidized resources that artificially suppress capacity market clearing prices. The P3 Complaint proposed specific modifications to the MOPR and requested fast-track treatment, indicating that the schedule of the upcoming BRA requires market rule revisions to be in place by mid-April 2011.

On February 4, 2011, FERC issued its Notice of the Complaint and requested PJM’s answer and any other interventions, comments, or protests by February 22, 2011. On February 9, 2011, PJM held a teleconference with more than 270 attendees to explain its position on MOPR. While PJM agreed with P3 that the current MOPR is inadequate and needs to be revised, PJM noted that it did not fully agree with all the remedies proposed in the P3 Complaint. PJM explained that it would file a Section 205 filing in response to the Complaint and would include an alternative approach to addressing the concerns raised in the Complaint. On February 11, 2011, PJM submitted its Filing with its MOPR revision proposal docketed under ER11-2875-000. PJM requested that the proposed tariff changes become effective on April 13, 2011.

On February 14, 2011, the MD PSC, an intervener, filed a motion to consolidate the two proceedings (Dockets Nos. EL11-20-000 and ER11-2875-000) and establish a paper hearing with a 120-day schedule for initial and reply briefs. The MD PSC requested that FERC allow at least 60 days from its hearing order for interested parties to analyze both P3’s and PJM’s MOPR proposals and prepare initial briefs, supported with the testimony of expert witnesses, and at least 60 days to analyze interveners’ positions and prepare reply briefs and testimony.

On February 15, 2011, FERC issued an Order in Docket EL11-20-000 extending the comment date in that proceeding, i.e., P3’s Complaint, to March 4, 2011, and denying the MD PSC’s request to extend the comment period for 60 days.

On February 16, 2011, PJM filed an Answer to Motions for Consolidation and for Establishing of Paper Hearing Procedures. In its Answer, PJM supported consolidation of the two proceedings and opposed establishing an extended schedule for the paper hearings as requested by the MD PSC.

55 P3 has 12 members with more than 80,000 MW in PJM. In the Complaint, P3 raised concerns regarding the effectiveness of the existing MOPR to mitigate buyer’s market power under the RPM, pointing specifically to New Jersey’s and Maryland’s programs to facilitate new generation investment.
On February 22, 2011, the Board intervened in Docket EL11-20-000, and two days later the Board intervened in Docket ER11-2875-000. On March 4, 2011, many parties who intervened in the proceedings filed Comments and, in some cases, Protests, including the Board and MD PSC.

**PJM’s Proposed Changes**

**Updated Reference Values and Percentage Factor**

Under MOPR, PJM calculates Net Asset Class Cost of New Entry CONE values to establish a price screen for mitigating BRA bids by new entrants. In its Section 205 filing, PJM proposed three changes to the calculation methodology: (i) update the calculation of Net Asset Class CONE values to make them consistent with Net CONE values used in the RPM process; (ii) use consistent levelization calculations for the Net Asset Class CONE and Net CONE; and, (iii) adjust the percentage factor by which the mitigation screen is applied.\(^{56}\)

- The first change would align the Net Asset Class CONE values used for the MOPR with the Net CONE values used in RPM. At present, the Net Asset Class Cost CONE values used for the MOPR are below the Net CONE values used in the VRR curves and, thus, the Net Asset Class CONE values would be raised. PJM proposes to use the same underlying construction cost index for both MOPR and Net CONE purposes.

- The second change would eliminate levelization differences between the MOPR and Net CONE calculations, which had the effect of understating the MOPR cost estimates for combustion turbines (CTs) and CCs. According to PJM’s filing, the current MOPR is ambiguous with respect to the determination of the EAS revenue offset.\(^{57}\) PJM also proposed locational variability in the Net Asset Class CONE calculations that recognize differences in capital cost and EAS revenues associated with new entry.

- The third change would apply a higher percentage factor to set the MOPR screen at 90% of the Net Asset Class CONE. PJM estimated that applying the 90% factor would result in a MOPR screen in CONE Area 1 (which includes NJ) of $247.52/MW-day for a CT and $184.86/MW-day for a CC. Under PJM’s proposal, any new resource offered into the BRA, starting in May 2011, below these screens would be subject to the revised MOPR mitigation and, accordingly, less likely to clear in the first BRA and, perhaps, subsequent BRAs.

**Elimination of “Net Short” Criterion**

Previously, mitigation under MOPR applied only to net buyers of capacity, *i.e.*, parties who would gain from an artificial depression of capacity market clearing prices. If the Net Short

---

\(^{56}\) In the RPM process, Net CONE is equal to Gross CONE less net EAS revenues, *i.e.*, after fuel and variable operation and maintenance costs, for a hypothetical simple cycle CT unit. Net CONE is an input in developing the VRR demand curves.

\(^{57}\) The revised calculation for CTs would be identical, with some minor caveats for CC calculations.
criterion is eliminated as proposed by PJM, all new resources will be screened and subject to MOPR; net sellers would not be able to circumvent MOPR.\textsuperscript{58}

**Elimination of Impact Test**

Currently, MOPR is only applied if a new entrant would significantly (defined as 20%-30%, depending on the location) reduce clearing prices. PJM proposes to eliminate this MOPR condition. If this provision is accepted by FERC, there would be no way to justify a below-CONE-cost offer on the basis that the out-of-market resource does not materially impact RPM prices.

**Time Period for MOPR Application**

Under the existing MOPR, a new SOCA resource would be mitigated for one year only and capacity price impact benefits could materialize starting in the second year. If PJM’s proposed revision is accepted by FERC, new capacity would be mitigated until it cleared a BRA and then subsequently for two BRAs thereafter.

**Application of MOPR by Resource Type**

PJM proposed to keep the existing MOPR’s tolerance of a zero-price offer for nuclear, coal, hydro, and integrated gasification CC facilities. In addition, PJM proposed to add wind and solar facilities to the zero-price tolerance list. However, PJM proposed to eliminate the zero-price exception for “any upgrade or addition to an existing capacity resource” and also clarified that “self-supply” offers are not exempt from MOPR.

**Obtaining FERC Approval of Bids for Mitigated Resources**

PJM clarified that mitigated resources would have to obtain a determination from FERC on the acceptability of their offers. In effect, any mitigated resource would have to show that the MOPR screen is unjust and unreasonable as applied to its specific costs and revenue expectations. PJM further notes that the sufficiency of state policy justifications is a matter much better addressed to FERC.\textsuperscript{59}

On February 22, 2011, LS Power requested FERC’s determination if its West Deptford CC facility can be allowed to offer in the May 2011 BRA at a price lower than what PJM has proposed to be a reasonable competitive offer price under the revised MOPR. The matter was docketed under ER11-2936-000. In support of its application, LS Power submitted competitively sensitive cost-related information. On March 14, 2011, FERC ordered LS Power

\textsuperscript{58} It appears that closing this loophole was undertaken specifically in response to the Board’s current initiative because it was envisioned that the pool of bidders in the LCAPP program would include not just net buyers, but net sellers as well.

\textsuperscript{59} The nature of the evidentiary burden before FERC is a complex issue warranting the advice of counsel.
to provide all the materials earlier presented to FERC to the interveners under Protective Agreement. The next day LS Power withdrew its February 22, 2011 application.  

**MOPR Analysis and Risk Assessment in the Context of LCAPP**

The outcome of the MOPR-related proceedings at FERC is unclear at this time. In any event, the LCAPP Law places the risk of clearing in BRAs on generators; hence MOPR mitigation will be felt first and foremost by generators with SOCAs.  

If a SOCA generator clears a BRA, it is uncertain if the resulting New Jersey RCP will be lowered so that ratepayers would realize the capacity market benefits. Many of PJM’s proposed MOPR modifications would either reduce or preclude the realization of this particular ratepayer benefit. Based on LAI’s review of PJM’s proposed changes, LAI believes that the combined effect of the proposed MOPR adjustments promulgated by PJM may make it more likely, but not certain, that a seller with a SOCA will be mitigated. Such mitigation would jeopardize the generator’s ability to clear in a BRA unless the capacity market is sufficiently tight for a mitigated bid to clear. Therefore, LAI conservatively assumed that awarding SOCAs to generators through the LCAPP process will not affect RCPs in New Jersey.

6.8 **PRICE IMPACT ANALYSIS**

The addition of new capacity to the generation mix in PJM can have an effect on future market energy and capacity prices that can benefit New Jersey electric ratepayers over time. If more capacity is added in EMAAC (New Jersey, Delaware, the Delmarva Peninsula, and parts of southeastern Pennsylvania) than would have been added without the LCAPP, capacity prices affecting the New Jersey LDCs could be reduced. If the capacity added is more efficient than that which it might replace, it can have a lasting impact on average energy prices in EMAAC as well. LAI used a suite of licensed and proprietary models to simulate the effects of each proposal against a Reference Case over an evaluation period running from June of 2014 through May of 2033. The same models were used to simulate combinations of proposals as well.

**Energy Price Impact Analysis**

Each energy market simulation produced a table of hourly LMPs for each zone, including EMAAC. These hourly LMPs were multiplied by the corresponding hourly loads for the New Jersey EDC areas (estimated as a % of total EMAAC load from historical data). These hourly products were summed for each month and adjusted for actual days in the month, since the model actually simulates one week per month. The monthly sums of price-load products were aggregated into totals for each Delivery Year (June-May).

---

60 LAI believes that the outcome of this proceeding is a good indicator of the efficacy of appeal to FERC on the MOPR applicability. In LAI’s view, it appears evident that a generator that desires special consideration of the MOPR applicability at FERC would have to be prepared to overcome scrutiny and disclose sensitive information to its competitors with no guarantee of success.

61 As discussed in Section 4 of this report, generators will not be able to receive SOCA payments in Delivery Years for which capacity did not clear, but the SOCAs will be permitted to remain in force.
Energy Market Price Benefit was determined for each proposal case and for each portfolio case as the PV of the annual differences between the Reference Case and the case in question.

Unit Energy Market Price Benefit was determined for each eligible generator case as the Energy Market Price Benefit, divided by the proposed SOCA Capacity of the generator.

**Capacity Price Impact Analysis**

It is difficult to derive capacity market price impacts ascribable to LCAPP and the consequential addition of up to 2,000 MW (UCAP). This is because RCPs under the RPM mechanism are sensitive to small changes in capacity supply. Moreover, as discussed in the previous section, the anticipated implementation of mitigation procedures under revisions to MOPR renders speculative recognition of capacity price impacts in the quantification of expected benefits. Therefore, LAI decided to exclude any potential capacity price benefits realized by ratepayers in New Jersey as a result of the addition of LCAPP supply.

**6.9 Preference Weight for COD Prior to 2015 Delivery Year**

According to the LCAPP Law, eligible generators with credible claims to a first Delivery Year of 2015 are to be awarded a “weighted preference in addition to the net benefit ratepayer test” (P.L. 2011, c. 9, 3.b.(3)). The method for calculating the net benefit ratepayer test uses the PV method with a fixed present date and a fixed (18-year) duration, regardless of the bidder's project expected COD or first SOCA Delivery Year. The PV method implicitly provides a time-weighted preference for projects that commence operation earlier. In addition, a pre-specified PV credit (in $/kW of SOCA Capacity) was available to eligible generators expected to achieve a COD before June 1, 2014. The amount of the credit was determined by LAI to be a materially significant preference, as required by the LCAPP Law, without unnecessarily distorting the economic benefits of the facility in relation to projects that submitted a later expected COD. Eligible generators expected to enter commercial operation in later delivery years would all be treated equally, other than for the earlier preference implicit in the PV calculation.

**6.10 Net Load Cost**

Net Load Cost (NLC) is the measure of economic performance used to rank eligible generators and to compare different portfolios of eligible generators that were considered. NLC combines the direct costs of each proposed generator (the Net SOCA Cost), the Energy and Capacity Market Price Benefits, and, if applicable, the preference weight for 2015 Delivery Year projects.

- Unit Net Load Cost (UNLC) is determined separately for each eligible generator as Unit Net SOCA Cost, less the Unit Energy Market Price Benefit, less the Unit Capacity Market Price Benefit, and less any applicable 2015 Delivery Year preference weight. UNLC is expressed in present value $/kW of SOCA Capacity.

62 Energy prices are much less sensitive due to changes in capacity supplies.
- Total Net Load Cost (TNLC) for each eligible generator is the product of UNLC and proposed SOCA Capacity and is expressed in millions of PV dollars. TNLC is also calculated for each portfolio of Capacity Facilities considered, as the sum Total Gross SOCA Cost for all included Capacity Facilities, the Total RCP Credit based on the annual total capacity and the resultant RCP price forecast for each year, the Energy Market Price Benefit for the portfolio, and the Capacity Market Price Benefit for the portfolio.

- Cumulative Total Net Load Cost is a preliminary determination of the aggregated TNLC for a portfolio of eligible generators, ignoring any non-linearity in market effects. Applied to a set of eligible generators ranked by increasing UNLC, the cumulative TNLC shows the point at which either diminishing returns or positive total costs are obtained as additional eligible generators are added to a portfolio.

6.11 RANKING AND SELECTION PROCESS

Present Value Calculations

All financial calculations were performed in nominal dollars for each Delivery Year and discounted to a PV reference point at the beginning of the 2014/15 Delivery Year. The 8.37% discount rate used is the peak-load weighted average of the Weighted Cost of Capital (WACC) rates for the EDCs. The calculation is summarized in Table 12.

<table>
<thead>
<tr>
<th>Utility</th>
<th>2014 Peak Load</th>
<th>% of Total</th>
<th>WACC</th>
<th>Wtd WACC</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSE&amp;G</td>
<td>10,901</td>
<td>52.8%</td>
<td>8.21%</td>
<td>4.335%</td>
</tr>
<tr>
<td>RECO</td>
<td>433</td>
<td>2.1%</td>
<td>8.50%</td>
<td>0.172%</td>
</tr>
<tr>
<td>JCP&amp;L</td>
<td>6,539</td>
<td>31.7%</td>
<td>8.21%</td>
<td>2.692%</td>
</tr>
<tr>
<td>AEC</td>
<td>2,773</td>
<td>13.4%</td>
<td>8.69%</td>
<td>1.177%</td>
</tr>
<tr>
<td>Total</td>
<td>20,646</td>
<td>100.0%</td>
<td>8.37%</td>
<td></td>
</tr>
</tbody>
</table>

The WACC values for the utilities are based on debt interest rates, preferred stock dividend rates, and common equity return rates provided to LAI by Board Staff, without consideration for tax effects.

Consideration of Alternative SOCA Price Options

The nine SOCA pricing options which survived the eligibility and qualification process represent five different generators. Four of these generators offered two valid pricing options. One of the five offered only one valid pricing option. Since only a single pricing option can be selected for

---

63 If after-tax WACC values had been used, the combined rate would have been about 7%, while if before-tax WACC values had been used, the combined rate would have been about 11.8%. Use of either of these rates would not have changed the selection of recommended generators, but it would have changed the magnitude of present values presented.
any generator, the first step in the ranking and selection process was to compare the alternative options offered for each generator and select one for use in ranking the generators.

Two generators offered options with the same SOCA term (first Delivery Year, number of Delivery Years offered). The options were compared based on the PV of the SOCP schedule and the option with the lowest such PV sum was selected for each generator.

One generator offered options with and without dual fuel capability. The SOCP for “gas-only” was slightly less than for “dual-fuel” in each year, resulting in a small but significant difference in PV of payments. Since the energy and capacity market analysis was not designed to capture any differential price effects associated with the dual fuel capability, it was determined that the “gas-only” pricing should be selected. If the sponsor finds that dual fuel capability would enhance the project economics at the “gas-only” SOCP level, such capability could be added without additional ratepayer support vis-à-vis higher SOCA payments over the 15-year SOCA term. On this basis LAI recommends the selection of the gas-only SOCP level. Board Staff and Counsel concur.

One generator offered options for 9-year and 15-year SOCA terms. With the RCP price forecast for the case, Unit Net SOCA Cost for the generator would be slightly higher with the 9-year option, since the forecast RCPs are slightly higher than the SOCP series for years 10 through 15 of the SOCA term. LAI observed that the 9-year term was beneficially priced insofar as the SOCA price did not appear to incorporate a risk premium to account for the project’s market exposure to uncertain BRA clearing prices in years 10 through 15 of the SOCA term. In terms of the total LCAPP portfolio recommended by Agent, LAI noted that there are portfolio benefits associated with the 9-year option rather than the 15-year SOCA term. Nevertheless, on an expected value basis LAI determined it is sensible to select the 15-year SOCA term rather than the 9-year term. Although the value of the fixed-for-variable swap on capacity price for years 10 through 15 of the SOCA term is inherently subject to measurement error, there is also the potential for significant financial upside if capacity prices appreciate relative to the forecast of BRA clearing prices in the last six years over the planning horizon. Through the technical lens of incremental benefit versus incremental cost, LAI reports that the benefit-to-cost ratio for the last six years remains greater than 1.0 from a ratepayer perspective on an expected value basis. For these reasons, LAI recommends the 15-year term for this generator rather than the 9-year term. Board Staff and Counsel concur.

### Ranking of Generators based on Selected Price Options

UNLC was calculated for each of the five eligible generators using the selected pricing options, where applicable. The list was then sorted by increasing UNLC to provide a “supply curve” of generators. Plotted in Figure 13 are cumulative Total Gross SOCA Cost, Total Net SOCA Cost, and Total Net Load Cost against cumulative SOCA Capacity. The total eligible Capacity from five generators is just under 3,000 MW. The first three generators total 1,948 MW, slightly less than the 2,000 MW procurement limit. The Gross SOCA Cost curve shows that each sequential generator has a higher Unit Gross SOCA Cost, represented by the slope of each segment. The Net SOCA Cost curve shows that the first two generators have negative Net SOCA Costs, while the third generator has a slightly positive Net SOCA Cost. The remaining two generators have significantly positive Net SOCA Cost. When Energy Market Price Benefit is included, as shown
by the Net Load Cost curve, cumulative cost decreases through the first three generators, is roughly level with the fourth, and then increases significantly with the fifth.

**Figure 13. Cumulative Cost v. Cumulative Capacity**

![Cumulative Cost graph](image)

**Evaluation of Generator Portfolios**

In order to capture any non-linearity in energy market effects when combining more than one generator, two portfolio cases were evaluated. The first case includes the two lowest UNLC generators and the second case includes the three lowest UNLC generators. Based on concerns regarding the potential applicability of MOPR, LAI has zeroed out any potential Capacity Market Price Benefit for individual generators or for portfolio cases. A MarketSym simulation was performed for each of the two portfolio cases to determine Total Energy Market Price Benefit. These were combined with the sums of the relevant generator Total Gross SOCA Costs and Total Net SOCA Costs to obtain portfolio TNLC. Figure 14 below shows the breakout of TNLC for the “best” generator alone and for portfolios adding the second and then the third lowest UNLC generators to reach a total SOCA capacity of less than 2,000 MW. The TNLC for the recommended portfolio of three SOCAs yields a benefit of $1.8 billion. Notably, Figure 13 underscores the important point that the energy market effects are roughly additive when the second and third eligible generators are combined in the recommended portfolio.
Each generator selected adds to the ratepayer fixed payment burden, as shown by the red bars, but provides a credit in terms of expected market capacity price offsets within the SOCA settlement mechanism. The value of the credit ascribable to the administration of the SOCA against capacity market clearing prices in PJM’s BRA is greater than the PV of the cost obligation set forth in the recommended SOCA portfolio. Based on LAI’s forecast of BRA capacity prices of relevance to New Jersey, the SOCAs provide a no-cost hedge on capacity prices over the 15-year term of each SOCA. The Energy Market Price Benefit can be considered a dividend payout on New Jersey’s investment in LCAPP. Based on the results of this procurement, LAI notes that a hypothetical portfolio greater than the 2,000 MW procurement limit set forth in the LCAPP Law would result in higher fixed payment obligations that are not offset by RCP credits and potential energy market benefits. More to the point, the three-generator portfolio recommended by Agent is advantageous relative to the two-generator portfolio.
7 RECOMMENDATIONS

7.1 RECOMMENDED WINNERS

After evaluating the conforming SOCP bids, the Agent has identified three eligible generators to be recommended for SOCA awards, with a total UCAP of 1,948.5 MW, as listed in Table 13. The locations of these generators are shown in Figure 15.

Table 13. Recommended SOCA Awards

<table>
<thead>
<tr>
<th>Sponsor</th>
<th>Newark Energy Center</th>
<th>Old Bridge Clean Energy Center</th>
<th>Woodbridge Energy Center</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hess Newark, LLC</td>
<td></td>
<td>New Jersey Power Development LLC</td>
<td>CPV Shore, LLC</td>
</tr>
<tr>
<td>Unforced Capacity</td>
<td>625.0 MW</td>
<td>660.1 MW</td>
<td>663.4 MW</td>
</tr>
<tr>
<td>Location</td>
<td>Newark, NJ</td>
<td>Old Bridge, NJ</td>
<td>Woodbridge, NJ</td>
</tr>
<tr>
<td>Technology Type</td>
<td>Combined Cycle</td>
<td>Combined Cycle</td>
<td>Combined Cycle</td>
</tr>
<tr>
<td>Fuel Type</td>
<td>Natural Gas</td>
<td>Natural Gas</td>
<td>Natural Gas</td>
</tr>
<tr>
<td>First SOCA Year</td>
<td>2016-2017</td>
<td>2015-2016</td>
<td>2015-2016</td>
</tr>
<tr>
<td>Selected Pricing Option(^{64})</td>
<td>Option B</td>
<td>$11 Initial Year then tapered</td>
<td>Option #2, Gas-only</td>
</tr>
<tr>
<td>Term</td>
<td>15 years</td>
<td>15 years</td>
<td>15 years</td>
</tr>
</tbody>
</table>

\(^{64}\) Represents pricing option names as provided by bidders.
7.2 PORTFOLIO BENEFITS SUPPORTING SELECTION

Ratepayer Economic Benefits

Even without a requirement to procure 2,000 MW of UCAP from new base load or mid-merit generators, the incremental net ratepayer economic benefits are positive up to the 1,948.5 MW (UCAP) provided by the three recommended SOCA awards. Irrespective of the 2,000 MW LCAPP limit, the other eligible generators offered capacity that would result in disbenefits, i.e., be dilutive.

Environmental Benefits

The development of nearly 2,000 MW (UCAP) of efficient, gas-fired CC projects in New Jersey will, in the aggregate, reduce net emissions of air pollutants by displacing existing generation which has higher emission rates of NOx, SO2, mercury, and greenhouse gases.65 The average net

---

65 We expect that PM emissions will also be reduced, but the Agent did not have access to a reliable and readily available database of PM emission rates for existing generation.
annual reductions of these pollutants and greenhouse gases are significant. The reductions are equivalent, on an order-of-magnitude basis, to the annual emissions of roughly 250-MW of coal-fired generation at a 100% capacity factor. The MarketSym model used to simulate the energy market also tracks emissions of SO\(_2\), NO\(_x\), and CO\(_2\) on a unit-specific basis. Mercury is accounted for in a post-processor using fuel consumption for each coal-fired plant in the system and the unit emission rate on a lb per fuel input basis.\(^6^6\) The net impact on air emissions ascribable to the construction of the recommended gas-fired CC plants was computed by deducting the total annual emissions of each pollutant in the Reference Case from the Recommended SOCA Portfolio Case.

With respect to NO\(_x\) and SO\(_2\), LAI’s modeling indicates that commercialization of the recommended SOCA portfolio will have a net impact of reducing emissions across the PJM portion of the study area, as shown in Figure 16. Negative values signify a reduction in annual emissions ascribable to the recommended portfolio, relative to the Reference Case. All figures showing annual emissions are on a calendar year and not Delivery Year basis. Future regulatory-driven reductions in SO\(_2\) and NO\(_x\) emissions may not have not been fully captured in this model. It is likely that the benefits shown in this figure would be somewhat reduced as coal- and oil-fired plants that do not now currently have SCR will invest in upgraded control systems to comply with future federal requirements under the proposed EPA Transport Rule.\(^6^7\)

If the comparison is performed for only fossil-fueled plants located within the State of New Jersey, the impact on local emissions of SO\(_2\) emissions is limited to the first two years of the forecast, before the expected retirement of B.L. England. Thereafter, the impact on SO\(_2\) emissions from sources within New Jersey is negligible, as shown in Figure 17. With respect to NO\(_x\), the emissions from sources within the State of New Jersey are forecasted to increase slightly when the three new gas-fired CC plants are commercialized. The increase in local NO\(_x\) emissions but decrease in regional emissions indicates that a significant amount of the generation that would be displaced by the recommended new gas-fired capacity in New Jersey is located in PJM states outside of New Jersey. Nonetheless, New Jersey residents will still experience cleaner air as a result of the commercialization of the recommended portfolio. Numerous studies conducted by regional air planning groups indicate that under typical climatic conditions, New Jersey is downwind of other PJM states. Pollutants from electric generation that contribute to high ozone concentrations and haze in New Jersey – NO\(_x\) and SO\(_2\) – are transported from upwind states.\(^6^8\)

\(^{66}\) Emission rates in MarketSym are based on Continuous Emission Monitoring System data submitted by generators to the EPA. The mercury emission rates for the coal-fired plants were derived from eGRID, an EPA database, available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html, eGRID emission rates were adjusted to reflect more stringent state emission limits and the expected reductions mandated by proposed federal Utility MACT rules beginning in 2016. For those units that exceed the proposed Utility MACT emission limits, the eGRID emission rate was replaced with the proposed limit under Utility MACT, 0.001 lb/GBtu, starting in the proposed first compliance year.

\(^{67}\) Plants that can not rationalize new investment for environmental upgrades are assumed to retire in all cases.

\(^{68}\) See for example, information provided by NJDEP at: http://www.state.nj.us/dep/baqp/model.html and Ozone Transport Commission, “The Nature of the Ozone Air Quality Problem in the Ozone Transport Region: A Conceptual Description,” October 2006, revised August 2010., available at:
Figure 16. PJM Change in Annual Emissions of NOx and SO2 Associated with Recommended SOCA Portfolio

Figure 17. New Jersey Change in Annual Emissions of NOx and SO2 Associated with Recommended SOCA Portfolio

http://www.nescaum.org/.../2010_o3_conceptual_model_final_revised_20100810.pdf
With respect to mercury, a similar reduction in mercury emissions across the PJM portion of the study area can be seen in Figure 18. Local emission reductions within only New Jersey are also expected. The state-wide air quality benefits are important in the case of mercury. Mercury emissions from point sources, such as coal-fired power plants, have been shown to create a local “hot spot,” although there are also regional and global contributions.69

Within the PJM portion of the study area, New Jersey, Maryland and Delaware have promulgated regulations limiting mercury emissions from coal-fired plants. Based on the compliance date of these regulations, operating coal plants in these states will have complied with the new state-wide limits prior to the in-service date of the recommended portfolio. All remaining states within the study area will become subject to federal Utility MACT rules by 2016, assuming that the rules proposed by EPA on March 16, 2011 are finalized. Absent the investment in environmental upgrades mandated by these rules, the avoided mercury emissions ascribable to the recommended portfolio would have been greater.

**Figure 18. New Jersey and PJM Change in Annual Emissions of Mercury Associated with Recommended SOCA Portfolio**

![Graph showing change in annual emissions of mercury from 2015 to 2032 for New Jersey and PJM.]

CO₂, the principal greenhouse gas, is a global environmental concern, and therefore must be viewed from the model system-wide perspective. Figure 19 shows the change in annual CO₂ emissions across the entire modeled system, when the recommended portfolio is compared to the

---

Reference Case. Gas-fired plants produce about 117 lbs of CO₂ for each MMBtu of fuel combusted\textsuperscript{70}. In the case of residual fuel oil and coal, the emission rates are approximately 173 and 210 lbs per MMBtu, respectively. Modeling indicates that the recommended efficient gas-fired CC plants will displace more carbon-intensive oil- and coal-fired generation and/or less efficient gas-fired generation across in the system, thereby reducing net CO₂ emissions. Results of this comparison are presented in Figure 19.

![Figure 19. System-wide Change in CO₂ Annual Emissions of CO₂ Associated with Recommended SOCA Portfolio](image.png)

All of the recommended projects propose to use state-of-the-art evaporative cooling tower systems, minimizing the use and discharge of cooling water. In addition, two of the three generators, the Newark Energy Center and the Woodbridge Energy Center, will be located on remediated brownfield sites. The beneficial reuse of formerly impaired properties represents a significant environmental benefit that may ultimately confer additional economic benefits as well.

Community Benefits

All three recommended generators appear to have community support, evidenced by one or more letters from local government officials, businesses, and labor unions, and no known opposition.

Each recommended generator is in the process of negotiating a PILOT or Host Community Benefit package, so local property tax or other community payments cannot be quantified at this time.\footnote{For a typical level of PILOT for a generation facility of the size of the recommended projects, the local employment and income benefits could be substantial if the additional community revenue is used to expand services. Alternatively, the additional revenue could induce further local economic benefits to the extent it is used to minimize local property taxes.}

Based on information provided by the applicants plus other information on generic CC facility construction costs and operations costs, the potential employment impacts of the three projects was estimated with use of a standard regional economic input-output model, IMPLAN.\footnote{The IMPLAN model and the latest available (2009) database for the state of New Jersey were licensed by LAI from MIG, Inc., the developer of the IMPLAN software and associated regional database products.} The three applicants provided similar information regarding the amount of direct construction labor and the type of expenditures expected to be procured from local New Jersey firms. The vast majority of construction labor is expected to be provided by New Jersey residents, and all of the on-site operations and maintenance positions are expected to be filled by workers living in New Jersey. Based on information regarding the numbers of construction and operations jobs, and the New Jersey shares of expenditures by type of materials and components, approximate gross employment creation impacts were estimated.\footnote{LAI used publicly-available information on typical construction cost and operations costs breakdowns for a CC facility located in New Jersey to allocate the total labor and non-labor expenditure information provided by the applicants into IMPLAN industries. LAI also made specific assumptions regarding the portion of materials and services expenditures that would likely be procured from New Jersey providers. For example, none of the power island costs were assumed to be provided by New Jersey firms, while all of the concrete and a portion of the fabricated steel products were assumed to be made by New Jersey firms.} The IMPLAN model calculated the “indirect” employment gain to New Jersey from the supply chain effects of additional business activity throughout New Jersey resulting from the direct expenditures for labor services and materials, and the “induced” employment gain from households having additional income from wages, salaries, and proprietors’ earnings.

The results of the employment impact analysis is shown in Figure 20(a) for construction activity impacts and in Figure 20(b) for permanent operations activity impacts. For consistency with employment impacts reported by all New Jersey state agencies, one full-time equivalent (FTE) job-year is defined as 1,820 hours. In actuality, many construction workers and some operations workers would work more than 1,820 hours per year, so a smaller number of positions would be filled.\footnote{For example, one publicly-available engineering estimate of operations labor specifies 23 positions, a 2,080 hour work year, and certain overtime factors for the technical specialists. This information is equivalent to 27 FTEs defined as an 1,820 hour work year.} In FTEs, the three recommended facilities would directly create about 2,400 job-years during a construction period spanning two to three years, followed by about 80 permanent annual FTEs during operations over the facilities' lives of 30 years or more.
In addition, indirect and induced employment ripple effects of the construction and operations expenditures on materials and services provided by New Jersey firms as well as the wages and salaries received by workers directly engaged in construction and operations may create more jobs than the direct employment effects. However, the IMPLAN model used implicitly assumes the local economy has full employment, so that new jobs attract workers to the area and part of their income is spent on major items such as housing and autos. Given the current high unemployment and underemployment rates in New Jersey, some of the additional income during the near-term construction period, ending by early 2016, may instead be used to pay down household debt and for smaller expenditures on goods and services produced by New Jersey businesses, and under-utilized businesses may not hire as many additional workers in response to higher sales, resulting in less of a local multiplier effect than shown in Figure 20(a). Later, by the time the facilities begin operations, the unemployment rate is expected to be closer to the normal rate, so that more of the modeled multiplier effects during the operational years would be realized, closer to the level shown in Figure 20(b).
Attachment 1

Form of Standard Offer Capacity Agreement
Attachment 1A

Redline Showing Technical Changes
STANDARD OFFER CAPACITY AGREEMENT
STANDARD OFFER CAPACITY AGREEMENT

This STANDARD OFFER CAPACITY AGREEMENT ("Agreement"), dated as of [     ] ("Effective Date"), is entered into by and between [ UTILITY ], a corporation organized under the law of the state of New Jersey ("Utility") and [ CAPACITY SELLER ], a corporation organized under the law of [ ] ("Generator").

WHEREAS, the State of New Jersey has established the Long-Term Capacity Agreement Pilot Program ("LCAPP") to promote construction of qualified electric generation facilities pursuant to P.L. 2011 c. 9 (the "Act");

WHEREAS, the Act requires that each Electric Public Utility enter into a standard offer capacity agreement as described in the Act and in a form approved by the New Jersey Board of Public Utilities ("Board") with eligible generators approved by the Board;

WHEREAS, under the Act, this Agreement shall be irrevocable once the Board issues an order approving this Agreement;

WHEREAS, under the Act, neither the Board nor any other governmental agency of New Jersey shall have the authority (i) to rescind, alter, modify, or repeal this Agreement or an order approving rate recovery of LCAPP costs, (ii) to revalue, re-evaluate, or revise the amount of the LCAPP costs, or (iii) to determine that the LCAPP costs or the revenues to recover the LCAPP costs are unjust or unreasonable;

WHEREAS, Generator has not commenced, and intends to commence, construction of an [   ] megawatt ("MW") electric generation facility, as described in Attachment A, after January 28, 2011 (the “Capacity Facility”);

WHEREAS, Generator is willing to commit to offer and clear Unforced Capacity of the Capacity Facility into each Base Residual Auction conducted by the PJM Interconnection, L.L.C. ("PJM") for all Delivery Years through the Conclusion Date;

WHEREAS, Generator is willing to commit to offer all the electric energy output and ancillary services of the Capacity Facility into the PJM markets during the Delivery Term;

WHEREAS, Generator’s eligibility and selection to participate in the LCAPP have been approved by the Board;

WHEREAS, this Agreement is in the form approved by the Board;

WHEREAS, Utility is an Electric Public Utility; and

WHEREAS, Generator has caused Construction Period Security to be provided to Utility, dated as of the date hereof, in support of Generator’s obligations under this Agreement.

NOW, THEREFORE, in consideration of the foregoing and mutual terms and conditions set forth herein, and for further good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereby agree as follows:
SECTION 1
DEFINITIONS; RULES OF INTERPRETATION

1.1. Defined Terms. Unless otherwise required by the context in which any term appears, initially capitalized terms used herein have the following meanings:

“Act” means the New Jersey P.L. 2011 c. 9 that establishes the LCAPP.

“Affiliate” means, with respect to any Person, each Person that directly or indirectly controls, is controlled by, or is under common control with such designated Person. For purposes of this definition, “control” (including, with correlative meanings, the terms “controlled by” and “under common control with”), as used with respect to any Person, shall mean (a) the direct or indirect right to cast at least fifty percent (50%) of the votes exercisable at an annual general meeting (or its equivalent) of such Person or, if there are no such rights, ownership of at least fifty percent (50%) of the equity or other ownership interest in such Person, or (b) the right to direct the policies or operations of such Person.

“Agreement” means this Standard Offer Capacity Agreement dated as of [   ], 2011 by and between Utility and Generator.

“Annual Forecasted Peak Demand” means in the case of Utility, its forecasted peak demand and, in the case of another Electric Public Utility, the forecasted peak demand of such other Electric Public Utility, for a given Delivery Year as determined by PJM and published in the most recent PJM Load Forecast Report issued before the start of the Delivery Year.

“Applicable Law” means all legally binding constitutions, treaties, statutes, laws, ordinances, rules, regulations, orders, interpretations, permits, judgments, decrees, injunctions, writs and orders of any Governmental Authority or arbitrator that apply to the LCAPP or any one or both of the parties to this Agreement or the terms hereof.

“Associated Ancillary Services” means the quantity of ancillary services, generally used by PJM to support the reliable operation of its transmission system, associated with the Available Capacity Amount.

“Associated Energy” means the quantity of electrical energy, generally used by PJM to satisfy its load requirements, associated with the Available Capacity Amount.

“Automated Clearing House” or “ACH” means an electronic network for financial transactions administered by NACHA-The Electronic Payments Association.

“Available Capacity Amount” means the lesser of: (i) the quantity of Unforced Capacity from the Capacity Facility that is offered by Generator and cleared by PJM in the relevant Base Residual Auction, and (ii) the Awarded Capacity Amount.
“Awarded Capacity Amount” means [__] MW, the amount of Unforced Capacity for which the Board has approved Generator to enter into standard offer capacity agreements with the Electric Public Utilities pursuant to the Act.

“Awarded Commencement Date” means the first day of the first Delivery Year for which the Board has approved Generator to receive or make payments under standard offer capacity agreements with the Electric Public Utilities pursuant to the Act, which date is June 1, [__].

“Base Residual Auction” means the primary auction conducted by PJM as part of PJM’s Reliability Pricing Model to secure electrical capacity as necessary to satisfy the capacity requirements imposed under the PJM Reliability Assurance Agreement for the Delivery Year.

“Board” means the New Jersey Board of Public Utilities or any successor agency.

“Business Day” means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday.

“Calculation Dispute” is defined in Section 12.2.1.

“Capacity Facility” means the [__] MW electric generation facility to be constructed by Generator as further defined in Attachment A.

“Cash” means cash in United States Dollars and any investment of such cash held in escrow.

“Cash Escrow Agreement” means an agreement providing for the receipt, holding (in the United States), investment and disbursement of Cash held in escrow by a Qualified Bank, to provide either Construction Period Security or Delivery Term Security.

“Commencement Date” means the last to occur of: (i) the Awarded Commencement Date; and (ii) the date the Capacity Facility first provides Unforced Capacity to PJM by having previously cleared in a Base Residual Auction.

“Conclusion Date” means May 31, [__], which date shall not be altered by any delay or change in the Commencement Date or other provision under this Agreement.

“Construction Period” means the period commencing on the Effective Date and concluding on the date the Generator first provides Unforced Capacity to PJM by having previously cleared in a Base Residual Auction.

“Construction Period Security” means (i) a Letter of Credit, substantially in the form of Attachment B, to be provided to the Utility or (ii) Cash held in escrow for the Utility under a Cash Escrow Agreement, substantially in the form of Attachment C to be mutually agreed between the Utility and Generator, in support of the Generator’s obligations during the Construction Period in an amount defined in section 2.3.4.

“Defaulting Party” is defined in Section 9.1.1.
“Delivery Year” means each 12-month period from June 1st through May 31st numbered according to the calendar year in which it ends beginning on the Commencement Date and concluding on the Conclusion Date.

“Delivery Term” means the period commencing with the Commencement Date and concluding on the Conclusion Date.

“Delivery Term Security” means (i) a Letter of Credit, substantially in the form of Attachment D, to be provided to the Utility or (ii) Cash held in escrow for the Utility under a Cash Escrow Agreement, substantially in the form of Attachment E to be mutually agreed between the Utility and Generator, in support of the Generator’s obligations during the Delivery Term in an amount defined in Section 2.3.5.

“Dispute” is defined in Section 12.1.

“Early Termination Date” means the date determined in accordance with Section 9.1.

“Effective Date” is defined in the Preamble hereof.

“EFORd” means a measure calculated by PJM of the probability that an electric power generating unit will not be available due to a forced outage or forced derating when there is a demand on the unit to generate.


“Event of Default” is defined in Section 7.1.

“Facility Lender” means (i) any lender providing construction, interim, long-term, or refinancing debt or equity funds to Generator for the Capacity Facility, (ii) any trustee or agent acting on their behalf, and (iii) any Person providing interest rate protection agreements to hedge any of the foregoing obligations.

“Force Majeure” means an event or circumstance, such as natural catastrophes, terrorism, war, riots, or acts of God, that (i) prevents one party from performing its obligations under this Agreement; (ii) is not within the reasonable control of, or the result of the negligence of, the claiming party; and, (iii) by the exercise of due diligence, the claiming party is unable to overcome or avoid, or cause to be avoided; provided, however, notwithstanding the foregoing, none of the following events or circumstances will constitute Force Majeure: (a) the loss or failure of Generator’s fuel supply, except when caused by Force Majeure; (b) the breakdown of Generator’s plant and/or equipment, except when caused by Force Majeure; and (c) an occurrence or an event that causes an economic hardship to a party.

“Generator” means a developer of an electric power generating facility that the Board has determined to qualify as eligible pursuant to the Act and is named in the Preamble hereof.
“Governmental Authority” means any international, national, federal, provincial, state, municipal, county, regional or local government, administrative, judicial or regulatory entity with jurisdiction over any party hereto, this Agreement, the LCAPP, or PJM, and includes any department, commission, bureau, board, administrative agency or regulatory body of any government.

“Interest Rate” means for any date, the per annum rate of interest equal to the yield on Two-Year U.S. Treasury Notes as may be published in The Wall Street Journal on such day (or if not published on such day the most recent preceding day on which published) plus sixty (60) basis points.

“Illegality” is defined in Section 8.1.1.

“Invalidity of the Act” is defined in Section 8.1.2.

“Letter of Credit” means an irrevocable standby letter of credit provided by a Qualified Bank to provide either Construction Period Security or Delivery Term Security.

“Locational Deliverability Area” or “LDA” means the PJM sub-regions used to calculate Resource Clearing Prices as part of the Reliability Pricing Model.

“Long-Term Capacity Agreement Pilot Program” or “LCAPP” is the program established by P.L. 2011 c. 9 to promote construction of qualified electric generation facilities.

“Month” means a calendar month commencing on the first day of such month and ending on the last day of such month.

“MW” means megawatt.

“NACHA Operating Rules” means the rules issued by NACHA – The Electronic Payments Association for the administration of the Automated Clearing House.

“Non-Defaulting Party” is defined in Section 9.1.1.

“Payment Date” is defined in Section 2.2.

“Person” means an individual, partnership, corporation, limited liability company, joint venture, association, trust, unincorporated organization, Governmental Authority, or other form of entity.

“PJM Interconnection, L.L.C.” or “PJM” means the Regional Transmission Organization that manages the regional, high-voltage electricity grid serving New Jersey and all or parts of other states and, among other things, administers the Reliability Pricing Model, and any successor.

“PJM Market Rules” means the rules, standards, procedures, and practices set forth in the PJM Tariff, PJM Operating Agreements, PJM Reliability Assurance Agreement, PJM Consolidated Transmission Owners Agreement, PJM Manuals, PJM Regional Practices

“PJM Markets” means the capacity, energy, and ancillary services markets administered by PJM.

“Qualified Bank” means a United States commercial bank or similar financial institution that has assets of at least $5 billion and a senior long-term unsecured debt rating of at least “A” by Standard & Poor’s, “A2” by Moody’s Investors Service, or “A” by Fitch Ratings.

“Reliability Pricing Model” or “RPM” means PJM’s capacity-market model that secures capacity on behalf of electric load serving entities to satisfy load obligations not satisfied through the output of electric generation facilities owned by those entities or otherwise secured by those entities through bilateral contracts.

“Resource Clearing Price” or “RCP” means the clearing price expressed in $/MW-day for Unforced Capacity established by the Base Residual Auction for the LDA in which the Capacity facility is located and the applicable Delivery Year as posted by PJM.

“RPM Rules” means the provisions of PJM’s tariffs and agreements accepted by the Federal Energy Regulatory Commission and the provisions of PJM’s manuals governing the Reliability Pricing Model, as in effect from time to time during the term of this Agreement.

“Standard Offer Capacity Price” or “SOCP” means the price for each Delivery Year at which the Board has approved Generator to enter into this Agreement with the Utility pursuant to the Act, which price is listed in Attachment F to this Agreement.

“Termination Date” means the earlier to occur of (i) the Conclusion Date or (ii) the Early Termination Date.

“Termination Event” is defined in Section 8.1.

“Total Annual Forecasted Peak Demand” for a given Delivery Year means the sum of the Annual Forecasted Peak Demands for each Electric Public Utility for such Delivery Year.

“Transaction” means the calculations, payments and payment obligations under Section 4.1 and the related provisions of this Agreement (including without limitation Section 2.1).

“Unforced Capacity” means the capacity of a capacity resource that accounts for the EFORd of that capacity resource and as periodically determined by PJM.

“Unpaid Amounts” owing to any party means, with respect to an Early Termination Date, the amounts that became payable to such party under Section 2.1 in respect of the Transaction on or prior to such Early Termination Date (including amounts not paid by the other party on the ground of the occurrence of an Event of Default, in accordance with Section 2.5) and which remain unpaid as at such Early Termination Date, together with (to the extent permitted under Applicable Law) interest from (and including) the date such amounts were to have been paid to (but excluding) such Early Termination Date, at the Interest Rate. Such amounts of interest will
be calculated on the basis of a 360-day year, daily compounding and the actual number of days elapsed.

“Utility” is defined in the Preamble hereof.

“Utility’s Load Ratio” means the percentage derived by dividing Utility’s Annual Forecasted Peak Demand by Total Annual Forecasted Peak Demand, both for a given Delivery Year, such that the sum of the Utility Load Ratios for the Electric Public Utilities shall always equal 100%.

1.2. Rules of Interpretation

1.2.1. General. Unless otherwise required by the context in which any term appears, (a) the singular includes the plural and vice versa; (b) references to “Articles,” “Sections,” “Schedules,” “Annexes,” “Appendices” or “Exhibits” (if any) are to articles, sections, schedules, annexes, appendices or exhibits hereof; (c) all references to a particular entity or an electricity or gas market price index include a reference to such entity’s or index’s successors and (if applicable) permitted assigns; (d) the words “herein,” “hereof” and “hereunder” refer to this Agreement as a whole and not to any particular Section or subsection hereof; (e) references to this Agreement include a reference to all appendices, annexes, schedules and exhibits hereto, as the same may be amended, modified, supplemented or replaced from time to time; (f) the masculine includes the feminine and neuter and vice versa; (g) the definitions of terms herein shall apply equally to the singular and plural forms of the terms defined; (h) “including” means “including, without limitation” or “including, but not limited to”; and (i) the word “or” is not necessarily exclusive.

1.2.2. Terms Not to be Construed For or Against Either Party. Each term hereof will be construed simply according to its fair meaning and not strictly for or against either party. No term hereof will be construed against a party on the ground that the party is the author of that provision.

1.2.3. Headings. The headings used for the sections and articles hereof are for convenience and reference purposes only and will in no way affect the meaning or interpretation of the provisions hereof.

1.2.4. Rounding. All calculations, including but not limited to RCP, New Jersey RCP, Available Capacity Amount, and Utility Load Ratios, will be rounded to the nearest third decimal place.

SECTION 2
OBLIGATIONS

2.1. General Conditions. Each party will make each payment specified herein to be made by it, including without limitation the payments under Section 2.2, subject to Section 2.5 and the other provisions hereof.
2.2. Calculation and Payment of Transaction Amounts. In the case of the first Delivery Year, no less than thirty (30) calendar days prior to the Awarded Commencement Date and, in the case of each subsequent Delivery Year, no less than thirty (30) calendar days prior to the commencement of such Delivery Year, Utility will provide a statement to Generator of the result of the calculation under Section 4.1 for the Delivery Year, specifying the party obligated to make payments with respect to such Delivery Year, and the monthly amount of such payments, including any correction made under Section 2.1. The party obligated to make payments will make such payments with respect to each Month on or before the last Business Day of the subsequent Month (the “Payment Date”) to the account specified herein in freely transferable funds via electronic funds transfer through a system that provides for final credit no later than one business day after transfer. The system for making such electronic funds transfers may be the ACH, in which case the paying party will originate the ACH credit for receipt the following Business Day. Each party agrees to be bound by the NACHA Operating Rules in connection with payments made via ACH and agrees that the origination of all ACH transactions will comply with applicable provisions of U.S. law. Whenever payments are made via ACH, the receiving party hereby authorizes the paying party to initiate credit entries to the account of the receiving party at the receiving party’s financial institution as set forth in Section 2.6. This authorization will remain in full force and effect until a party has received prior written notice from the other party of its termination, such notice to be provided in such time and in such manner as to afford the party receiving such notice a reasonable opportunity to act on it.

2.3. Obligations of Generator.

2.3.1. Generator shall use all commercially reasonable efforts to cause the Capacity Facility to qualify under the RPM Rules as a capacity resource in an amount no less than the Awarded Capacity Amount for the Base Residual Auction associated with each Delivery Year during the term of this Agreement, commencing upon the Awarded Commencement Date.

2.3.2. Generator shall use all commercially reasonable efforts to cause the Capacity Facility to achieve commercial operation no later than the Commencement Date.

2.3.3. Throughout the Delivery Term, Generator shall:

(a) Cause the Capacity Facility to comply with all obligations of a capacity resource under the RPM Rules, including without limitation the obligations relating to the submission of offers to supply electric energy and ancillary services in PJM markets, and Generator shall bear all costs associated with such compliance, including without limitation all fees and penalties imposed by PJM;

(b) Submit supply offers for an amount of Unforced Capacity no less than the Awarded Capacity Amount from the Capacity Facility in accordance with the RPM Rules in the Base Residual Auction associated with each Delivery Year during the term of this Agreement, such that the Unforced Capacity shall be offered at the lowest commercially reasonable price under the RPM rules;

(c) Submit supply offers from the Capacity Facility for the maximum amount of Associated Energy that the Capacity Facility can provide in the PJM day-ahead energy market
in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Energy shall be offered at the lowest commercially reasonable price under PJM’s Market Rules;

(d) Submit supply offers from the Capacity Facility for the maximum amount of Associated Ancillary Services that the Capacity Facility can provide in the PJM ancillary services markets in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Ancillary Services shall be offered at the lowest commercially reasonable price under PJM’s Market Rules;

(e) Neither physically nor financially withhold any Unforced Capacity up to the amount of Awarded Capacity, or Associated Energy and Associated Ancillary Services, from the Capacity Facility;

(f) Provide on a timely basis (which, in the case of documentation provided to Generator by PJM, shall mean within five (5) Business Days of Generator’s receipt of such documentation) all documentation required by Utility to make the calculations and notifications required by Sections 2.2 and 4.1, including without limitation: (i) documentation provided to Generator by PJM after the conclusion of each Base Residual Auction showing the amount of Unforced Capacity offered from the Capacity Facility and cleared by PJM in such Base Residual Auction; (ii) documentation provided to Generator by PJM in advance of each Delivery Year showing the all EFORd measurements for the Capacity Facility for the Delivery Year; (iii) the result of any capability test of the Capacity Facility conducted by PJM; (iv) documentation provided to Generator by PJM in advance of each Delivery Year showing the Available Capacity Amount for the Delivery Year or required to calculate the Available Capacity Amount for the Delivery Year; and (v) documentation notifying Generator of any correction to an input to a calculation, as provided in Section 2.9; provided that Generator may redact from any such documentation data that do not relate to the Capacity Facility;

(g) Provide on a timely basis all documentation reasonably requested by Utility to demonstrate Generator’s compliance with all of its obligations as set forth in this Section 2.3 and affirmative covenants as set forth in Section 6. Utility shall have the right, upon reasonable notice to Generator, to request such information once each year and, in addition, upon the occurrence of any event or upon Utility’s receipt of information that gives Utility reasonable grounds for concern in good faith as to Generator’s compliance with one or more such obligations;

(h) Prepare and file an annual certification to the Board within thirty (30) calendar days after the end of each Delivery Year describing the Generator’s compliance with Section 2.3.3 (b) through Section 2.3.3 (e) and any material actions taken by the Generator under this Agreement.

2.3.4. Cause to be provided to the Utility throughout the Construction Period, Construction Period Security in an amount to be calculated annually equal to the product of $10,000/MW and the Awarded Capacity Amount and the Utility’s Load Ratio, but in no case more than the product of $1 million, and the Utility’s Load Ratio. Such Construction Period Security shall be in the form of a Letter of Credit or Cash held in escrow by the Utility, which shall have the right to draw upon the Construction Period Security as provided in Section 9.4. In
the event of the application of any such Construction Period Security toward any amount owed hereunder to Generator the Generator shall have no obligation to increase the amount of the Construction Period Security beyond the initial amount provided.

2.3.5. Cause to be provided to the Utility throughout the Delivery Term, Delivery Term Security in an amount to be calculated annually equal to the product of $25,000/MW and the Awarded Capacity Amount and the Utility’s Load Ratio with the amount of Delivery Term Security declining pro rata at the conclusion of each Delivery Year over any remaining term of this Agreement. Such Delivery Period Security shall be in the form of a Letter of Credit or Cash held in escrow by the Utility, which shall have the right to draw upon the Delivery Term Security as provided in Section 9.4. In the event of the application of any such Delivery Term Security toward any amount owed hereunder to Generator the Generator shall have no obligation to increase the amount of the Delivery Term Security beyond the initial amount provided.

2.3.6. Fulfill all Generator’s obligations under, and otherwise comply with all terms of, the Construction Period Security and Delivery Term Security.

2.4. Obligations of the Utility. The Utility shall prepare and file an annual report to the Board within thirty (30) calendar days after the end of each Delivery Year describing (i) the status of this Agreement, (ii) the amount of Unforced Capacity and cost of associated Transactions made under this Agreement, (iii) the performance of the Generator in supplying Unforced Capacity and Associated Energy and Associated Ancillary Services under this Agreement, and (iv) any material actions taken by the Generator or the Utility under this Agreement. Nothing in this Agreement imposes upon Utility the obligation to monitor, enforce, or declare an Event of Default with respect to the price of Unforced Capacity, or the price or amount of Associated Energy or Associated Ancillary Services, which Generator offers in or supplies to any PJM Market.

2.5. Conditions Precedent to Obligations. Each obligation of each party under this Agreement is subject to (i) the condition precedent that no Event of Default with respect to the other party has occurred and is continuing, (ii) the condition precedent that no Early Termination Date has occurred or been effectively designated, and (iii) the Board has found that this Agreement is reasonable and that the Utility will be allowed full rate recovery of all prudent and reasonably incurred costs associated with this Agreement.

2.6. Accounts; Change of Account

2.6.1. Payments are to be made to the following accounts:

Generator:
Pay:
For the Account of:
Account Number:
Fed. ABA Number:

Utility:
Pay:
For the Account of:
Account Number:
Fed. ABA Number:

2.6.2. Either party may change its account for receiving a payment by giving written notice to the other party, which notice will be effective for the next payment date that is at least five Business Days after the effective date of such notice unless such other party gives timely notice of a reasonable objection to such change.

2.6.3. The parties agree that any payments hereunder shall be deemed made in full when confirmation is received from the financial institution holding the account into which payment is made that the payment has been successfully received in immediately available funds. Such confirmation shall be considered by the parties as conclusive evidence of receipt.

2.7. Default Interest; Other Amounts. Prior to the occurrence or effective designation of an Early Termination Date, a party that defaults in the performance of any payment obligation will, to the extent permitted by law and subject to Section 9.3.3, be required to pay interest (before as well as after judgment) on the overdue amount to the other party on demand for the period from (and including) the original due date for payment to (but excluding) the date of actual payment, at the Interest Rate. Such interest will be calculated on the basis of a 360-day year, daily compounding and the actual number of days elapsed. Each payment will be made in U.S. Dollars in freely transferable funds via electronic funds transfer, as set forth in Section 2.2, on the relevant Payment Date (or if that date is not a Business Day, on the next Business Day).

2.8. Calculations. Utility shall make all calculations of payments due under Sections 2.2 and 4.1 in accordance with the terms of this Agreement, in good faith and with commercial reasonableness, and its determinations and calculations will be binding, subject to the resolution of any Calculation Dispute. Inaccuracy in any calculation shall not be an Event of Default. The sole remedy of the parties with respect to any inaccuracy of a calculation will be the right (but not the obligation), to commence a Calculation Dispute.

2.9. Corrections to Input to Transaction Payment. If PJM revises to correct any of the inputs required for Utility to calculate any payment required under Section 4.1 within the time permitted by PJM’s applicable tariff rate or rate schedule for the revision of PJM charges, Utility will reflect the amount (if any) that is payable as a result of that correction (including without limitation interest on such amount payable from the date of original payment under Section 4.1 through the date of payment under this Section 2.9 at the Interest Rate) in the calculation of payment of payments due for the Delivery Year after Utility receives notice of the revision. Utility shall calculate the correction so as to place the parties in the same economic position after such payment as they would have been had the correct input been employed initially.

2.10. Substitution Return and Handling of Credit Support

2.10.1. Election to Change Form of Credit Support. With respect to the Construction Period Security or the Delivery Term Security, the Generator may, at any time and
from time to time, replace (i) a Letter of Credit with Cash held under a Cash Escrow Agreement, (ii) Cash held under a Cash Escrow Agreement with a Letter of Credit, or (iii) a Letter of Credit with a different Letter of Credit, provided that any such substitute Cash and Cash Escrow Agreement or substitute Letter of Credit (as the case may be) meets the requirements for Construction Period Security or Delivery Term Security, as applicable, whereupon the Utility shall cooperate with the Generator in obtaining the concurrent release, termination or return of the Letter of Credit or Cash and Cash Escrow Agreement (as the case may be) being replaced.

2.10.2. Return of Original Credit Support Documents. Without limitation to the generality of the foregoing, the Utility shall return to the Generator all original Credit Support Documents, and all amendment, extension and other documents related thereto, within twenty (20) calendar days of the termination, cancellation or replacement thereof.

2.10.3. Handling of Cash Collateral. If any collateral in the form of Cash is expected to be or is received by the Utility pursuant to this Agreement, whether following a Letter of Credit drawing due to failure on the part of the issuer of the Letter of Credit to renew or extend the Letter of Credit or otherwise, the parties shall cooperate to cause such collateral in the form of Cash to be delivered as soon as practicable to a custodian to be held pursuant to a Cash Escrow Agreement. Any collateral in the form of Cash that is received and held by the Utility pending delivery to a custodian shall be segregated by the Utility from its other property and held exclusively in accounts with Qualified Banks.

SECTION 3
TERM AND TERMINATION

This Agreement is effective as of the Effective Date and will remain in effect until the later to occur of the Termination Date or the fulfillment by the parties of all obligations hereunder.

SECTION 4
TRANSACTIONS

4.1. Transactions.

4.1.1. If, for a Delivery Year, the SOCP is greater than the RCP then, subject to Section 2.5, Utility will pay Generator each Month during the Delivery Year one-twelfth of the product of (i) the difference between the SOCP and the RCP, (ii) the Available Capacity Amount, (iii) the number of days in the Delivery Year, and (iv) Utility Load Ratio, each for the applicable Delivery Year.

4.1.2. If, for a Delivery Year, the RCP is greater than the SOCP then, subject to Section 2.5, Generator will pay Utility each Month an amount equal to one-twelfth of the product of (i) the difference between the RCP and the SOCP, (ii) the Available Capacity Amount, (iii)
the number of days in the Delivery Year, and (iv) Utility Load Ratio, each for the applicable Delivery Year.

4.1.3. New Jersey RCP shall be calculated for each Delivery Year as the weighted average of the RCPs for the Electric Public Utilities, using the Utility Load Ratios as weights.

4.1.2. 

4.2. Structure of Transaction. Nothing in this Agreement shall entitle or obligate Utility to purchase, or take title to or delivery of, capacity, electric energy, or ancillary services from the Capacity Facility.

SECTION 5
REPRESENTATIONS AND WARRANTIES

5.1. Mutual Representations and Warranties. Each party represents to the other party, from the Effective Date, and, except as specified below, continuing throughout the Delivery Term, that:

5.1.1. It is duly organized and validly existing under the laws of the jurisdiction of its organization or incorporation and, if relevant under such laws, in good standing.

5.1.2. It has the power (i) to execute this Agreement, the Construction Period Security, Delivery Term Security and any other documentation relating hereto or thereto, (ii) to deliver this Agreement and cause to be delivered the Construction Period Security, Delivery Term Security and any other documentation that it is required by this Agreement to deliver and (iii) to perform its obligations hereunder or thereunder and has taken all necessary action to authorize such execution, delivery and performance.

5.1.3. As of the Effective Date, such execution, delivery and performance do not violate or conflict with any law applicable to it, any order or judgment of any court or other agency of government applicable to it or any of its assets or any contractual restriction binding on or affecting it or any of its assets.

5.1.4. Its obligations under this Agreement, the Construction Period Security, and Delivery Term Security constitute its legal, valid and binding obligations, enforceable in accordance with their respective terms (subject to applicable bankruptcy, reorganization, insolvency, moratorium or similar laws affecting creditors’ rights generally and subject, as to enforceability, to equitable principles of general application (regardless of whether enforcement is sought in a proceeding in equity or at law)).

5.1.5. As of the Effective Date, all governmental and other consents that are required to have been obtained by it with respect to this Agreement, the Construction Period Security, and the Delivery Term Security are in full force and effect and all conditions of any such consents have been complied with.
5.1.6. As of the Effective Date, no Event of Default or event which, with notice or the passage of time or both, would constitute an Event of Default has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations hereunder or under the Construction Period Security or Delivery Term Security.

5.1.7. All applicable information that is furnished in writing by or on behalf of it to the other party required by Section 6.1 is, as of the date of the information, true, accurate and complete in every material respect.

5.1.8. It is an “eligible contract participant” within the meaning of Section 1(a)18 of the Commodities Exchange Act, as amended.

5.1.9. In connection with the negotiation of, the entering into, and the confirming of the execution of, this Agreement: (i) it is acting as principal (and not as agent or in any other capacity, fiduciary or otherwise); (ii) the other party is not acting as a fiduciary or financial or investment advisor for it; (iii) it is not relying upon any representations (whether written or oral) of the other party other than the representations expressly set forth in this Agreement; (iv) the other party has not given to it (directly or indirectly through any other Person) any advice, counsel, assurance, guarantee, or representation whatsoever as to the expected or projected success, profitability, return, performance, result, effect, consequence, or benefit (either legal, regulatory, tax, financial, accounting, or otherwise) hereof; (v) it has consulted with its own legal, regulatory, tax, business, investment, financial, and accounting advisors to the extent it has deemed necessary, and it has made its own decision to enter into the Transaction based upon its own judgment and upon any advice from such advisors as it has deemed necessary, and not upon any view expressed by the other party; and (vii) it is entering into this Agreement with a full understanding of all the risks hereof and thereof (economic and otherwise), and it is capable of assuming and willing to assume (financially and otherwise) those risks.

5.1.10. It is a “United States person” (within the meaning of section 7701(a)(30) of the Internal Revenue Code of 1986, as amended, and is exempt from backup withholding under Internal Revenue Code section 3406 and relevant U.S. Department of the Treasury regulations.

5.2. Generator’s Representations and Warranties. Generator hereby represents and warrants to Utility as of the Effective Date that:

5.2.1. Generator’s selection to participate in the LCAPP has been approved by the Board.

5.2.2. Generator is approved by the Board pursuant to the Act as eligible to enter into standard offer capacity agreements with the Electric Public Utilities for the Awarded Capacity Amount at the SOCP.
5.2.3. Generator will not, either alone or in combination with any Affiliate of Generator that is eligible to participate in the LCAPP, enter into financially-settled standard offer capacity agreements for more than 700 MW of Unforced Capacity pursuant to the LCAPP.

SECTION 6
AFFIRMATIVE COVENANTS

Each party agrees with the other that, so long as either party has or may have any obligation hereunder:

6.1. Furnish Specified Information.

6.1.1. Each party will deliver to the other party such proof of the names, true signatures and authority of Persons signing this Agreement on its behalf as the other party may reasonably request upon execution hereof;

6.1.2. Generator will deliver to Utility on a timely basis:

(a) All information required by the Utility to perform the calculations specified in Sections 2.2 and 4.1, including without limitation information supplied to Generator by PJM;

(b) All documents, including all written notifications and other communications from PJM, related to Generator’s compliance or non-compliance with the RPM Rules;

(c) All additional documents required for Utility to provide an annual report to the Board as specified in Section 2.4.

6.2. Maintain Authorizations. Each party will use all reasonable efforts, including the maintenance of records and provision of notices, to maintain in full force and effect all consents, licenses or approvals of PJM and of any Governmental Authority or other authority that are required to be obtained by it with respect to this Agreement, the Construction Period Security, and the Delivery Term Security Agreement and its obligations hereunder and thereunder and will use all reasonable efforts to obtain any that may become necessary in the future.

6.3. Comply with Laws and RPM Rules. Each party will comply in all material respects with all Applicable Laws and orders and all RPM Rules to which it may be subject if failure so to comply would materially impair its ability to perform its obligations hereunder or under the Construction Period Security or Delivery Term Security.

6.4. Reporting Requirements. Generator shall be responsible for any recordkeeping, reporting and other requirements applicable to this Agreement under the Commodity Exchange Act, as amended, and the regulations of the Commodity Futures Trading Commission.
SECTION 7
EVENTS OF DEFAULT

7.1. Events of Default. The occurrence at any time with respect to a party of any of the following events constitutes an event of default (an “Event of Default”) with respect to such party:

7.1.1. Failure to Pay. Failure by the party to make, when due, any payment under this Agreement required to be made by it if such failure is not remedied on or before the third (3rd) Business Day after notice of such failure is given to the party.

7.1.2. Failure to Provide Information. Failure by Generator to provide to Utility such information or documentation required by Section 2.3.3 or Section 6.1.2 if such failure is not remedied on or before the fifth (5th) Business Day after notice of such failure is given to Generator by Utility.

7.1.3. Breach of Agreement. Failure by the party to comply with or perform any agreement or obligation (other than an obligation to make any payment under this Agreement or to provide information or documentation) to be complied with or performed by the party in accordance with this Agreement if such failure is not remedied on or before the thirtieth (30th) calendar day after notice of such failure is given to the party, or, in the case of a failure to comply with any applicable provision of the RPM Rules, within the time (if any) provided in the RPM Rules to remedy such failure.

7.1.4. Misrepresentation. A representation made or repeated by the party in this Agreement proves to have been incorrect or misleading in any material respect when made or repeated or deemed to have been made or repeated, and such misrepresentation is not cured within thirty (30) calendar days after such misrepresentation is made or repeated;

7.1.5. Bankruptcy. The party: (i) is dissolved (other than pursuant to a consolidation, amalgamation or merger); (ii) becomes insolvent or is unable to pay its debts or fails or admits in writing its inability generally to pay its debts as they become due; (iii) makes a general assignment, arrangement or composition with or for the benefit of its creditors; (iv) institutes or has instituted against it a proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditors’ rights, or a petition is presented for its winding-up or liquidation, and, in the case of any such proceeding or petition instituted or presented against it, such proceeding or petition (A) results in a judgment of insolvency or bankruptcy or the entry of an order for relief or the making of an order for its winding-up or liquidation or (B) is not dismissed, discharged, stayed or restrained in each case within fifteen (15) calendar days of the institution or presentation thereof; (v) has a resolution passed for its winding-up, official management or liquidation (other than pursuant to a consolidation, amalgamation or merger); (vi) seeks or becomes subject to the appointment of an administrator, provisional liquidator, conservator, receiver, trustee, custodian or other similar official for it or for all or substantially all its assets; (vii) causes or is subject to any event with respect to it which, under the Applicable Laws of any jurisdiction, has an analogous effect to any of the events specified in clauses (i) to (vi)
(inclusive); or (viii) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts; or

7.1.6. **Merger Without Assumption.** The party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer the resulting, surviving or transferee entity fails to assume all the obligations of such party hereunder or under the Construction Period Security or Delivery Term Security Agreement.

7.1.7. **Failure to Achieve the Commencement Date.** Generator fails to cause the Capacity Facility to achieve the Commencement Date by no later than two (2) years after the Awarded Commencement Date, except if an event of Force Majeure causes additional delays.

7.1.8. **Failure to Participate in a PJM Market.** Generator fails to submit a supply offer, consistent with Section 2.3.3 for its Unforced Capacity and the Associated Energy and Associated Ancillary Services from the Capacity Facility. Any Capacity Facility shall be required to bid no less than the Awarded Capacity Amount beginning with the Base Residual Auction associated with the Awarded Commencement Date and continuing through the Delivery Term, except if an event of Force Majeure delays the Commencement Date.

7.1.9. **Security Default.** With respect to Generator: (i) failure by Generator to comply with any provision of, or to perform any of its obligations under, either the Construction Period Security or the Delivery Term Security if such failure is continuing after any applicable grace period has elapsed; (ii) the expiration of, termination of, or failure to replace in accordance with Section 2.10 within five (5) Business Days after Utility has delivered notice to Generator of such failure, as appropriate, either the Construction Period Security or the Delivery Term Security prior to its intended expiration date; (iii) the failing or ceasing of either the Construction Period Security or the Delivery Term Security to be in full force and effect for its intended term; (iv) Generator disaffirms, disclaims, repudiates or rejects, in whole or in part, or challenges the validity of, the Construction Period Security or the Delivery Term Security; or (v) a default or event of default, howsoever characterized, occurs under the Construction Period Security or the Delivery Term Security.

**SECTION 8**

**TERMINATION EVENTS**

8.1. **Termination Events.** The occurrence at any time of any of the following events constitutes a Termination Event (a “Termination Event”).

8.1.1. **Illegality.** Due to the adoption of, or any change in, any Applicable Law after the Effective Date, or due to the promulgation of, or any change in, the interpretation by any court, tribunal or regulatory authority with competent jurisdiction of any Applicable Law after such date, it becomes unlawful (other than as a result of a breach by the party of Section 6.2) for a party:
(1) to perform any absolute or contingent obligation to make a payment or to receive a payment in respect of the Transaction or to comply with any other material provision of this Agreement;

(2) to perform any contingent or other obligation which the party has or any other material provision of this Agreement; or

(3) to provide or perform its obligations under the Construction Period Security or the Delivery Period Security.

8.1.2. Invalidity of the Act. If a court invalidates or declares unconstitutional the Act or portion thereof requiring or specifying some performance, right, or obligation of Utility or Generator.

SECTION 9 REMEDIES

9.1. Right to Terminate Following Event of Default or Termination Event.

9.1.1. If at any time an Event of Default with respect to a party (the “Defaulting Party”) has occurred and is then continuing, then the other party (the “Non-Defaulting Party”) may, by not more than twenty (20) calendar days notice in writing to the Defaulting Party specifying the relevant Event of Default, designate a day not earlier than five (5) Business Days after such notice is effective as an Early Termination Date.

9.1.2. If at any time a Termination Event has occurred and is then continuing, then either party in the case of an Illegality or an Invalidity of the Act, may, by not more than twenty (20) calendar days notice in writing to the other party specifying the relevant Termination Event, designate a day not earlier than five (5) Business days after such notice is effective as an Early Termination Date.

9.2. Effect of Designation.

9.2.1. If notice designating an Early Termination Date is given, the Defaulting Party shall have five (5) Business Days to cure any Event of Default. If after such five (5) Business Days the Event of Default or Termination Event is continuing, then the Early Termination Date will occur on the date so designated, whether or not the relevant Event of Default or Termination Event is then continuing.

9.2.2. Upon the occurrence or effective designation of an Early Termination Date, no further payments under Section 2.1 or 2.7 will be required to be made, and this Agreement shall be null and avoid, except with respect to the provisions hereof required to effect payments of the amounts, if any, payable in respect of an Early Termination Date, which amounts shall be determined and paid pursuant to Section 9.3.
9.3. **Payments on Early Termination.** If an Early Termination Date occurs, the following provisions will apply.

9.3.1. **Events of Default.** If the Early Termination Date results from an Event of Default, the Defaulting Party will pay the Non-Defaulting Party: (i) all Unpaid Amounts owing to the Non-Defaulting Party; (ii) all expenses payable under Section 9.5; and (iii), in the case of an Event of Default relating to participating in a Base Residual Auction, an amount equal to the product of (a) the amount, if any, by which the RCP for such Base Residual Auction exceeds the SOCP, (b) the Awarded Capacity Amount; (c) three hundred and sixty-five (365); (d) the Utility Load Ratio, and (e) the number of Delivery Years remaining in the Delivery Term starting with and including the Delivery Year associated with such Base Residual Auction.

9.3.2. **Termination Events.** If an Early Termination Date results from Section 8.1.1 (an Illegality) or Section 8.1.2 (an Invalidity of the Act), each party shall pay to the other all Unpaid Amounts owing pursuant to the terms of this Agreement.

9.3.3. **Notice and Payment.** The party designating an Early Termination Date shall provide notice of such Early Termination Date to the other party. Upon Utility’s issuance or receipt of such notice, Utility shall, as soon as practicable, calculate the amounts payable under Section 9.3.1 or 9.3.2, as applicable, and shall provide the calculation to the parties, specifying the party who is obligated to pay and the amount of such payment. An amount calculated as being due in respect of an Unpaid Amount will be payable, as applicable: (i) on the day that notice of the amount payable is effective (in the case of an Early Termination Date which is designated or occurs as a result of an Event of Default); or (ii) on the day which is two (2) Business Days after the date on which notice of the amount payable is effective (in the case of an Early Termination Date which is designated as a result of a Termination Event). Such amount will be paid together with (to the extent permitted under Applicable Law) interest thereon (before as well as after judgment), from (and including) the relevant Early Termination Date to (but excluding) the date such amount is paid, at the Interest Rate. Such interest will be calculated on the basis of daily compounding and the actual number of days elapsed.

9.4. **Rights Under Construction Period Security and Delivery Term Security**

9.4.1. **Parties’ Rights and Remedies.** If at any time an Early Termination Date has occurred as the result of an Event of Default or a Termination Event with respect to the Generator, then, unless the Generator has paid in full all of its obligations under this Agreement that are then due, the Utility may exercise one or more of the following rights and remedies:

(a) All rights and remedies available to the Utility under the terms of the applicable Letter of Credit or Cash Escrow Agreement, including without limitation the right to draw on such Letter of Credit and Cash held under such Cash Escrow Agreement;

(b) All other rights and remedies available to the Utility under applicable law as the beneficiary in the case of a letter of credit or secured party in the case of Cash held in escrow; and
(c) The right to set-off any amounts payable by the Generator with respect to any obligations under this Agreement against any Cash held on behalf of the Utility under any Cash Escrow Agreement.

9.4.2. Deficiencies and Excess Proceeds. The Utility will return to the Generator any Letter of Credit or Cash held on behalf of the Utility under a Cash Escrow Agreement remaining after liquidation, set-off and/or application under Section 9.4.1 after satisfaction in full of all amounts payable by the Generator with respect to any of its obligations under the Agreement. The Generator in all events will remain liable for any amounts remaining unpaid after any liquidation, set-off and/or application under such Section 9.4.1.

9.5. Expenses. A Defaulting Party will, on demand, indemnify and hold harmless the other party for and against all reasonable out-of-pocket expenses, including legal fees, incurred by the Non-Defaulting Party by reason of the enforcement and protection of its rights hereunder or under the Construction Period Security, the Delivery Term Security, or by reason of the early termination of the Transaction, including, but not limited to, costs of collection.

9.6. LIMITATION OF LIABILITY. NO PARTY WILL BE REQUIRED TO PAY OR BE LIABLE FOR INCIDENTAL, CONSEQUENTIAL, INDIRECT, OR PUNITIVE DAMAGES (WHETHER OR NOT ARISING FROM ITS NEGLIGENCE) TO ANY OTHER PARTY EXCEPT TO THE EXTENT THAT THE PAYMENTS REQUIRED TO BE MADE PURSUANT HERETO ARE DEEMED TO BE SUCH DAMAGES. IF AND TO THE EXTENT ANY PAYMENT REQUIRED TO BE MADE PURSUANT HERETO IS DEEMED TO CONSTITUTE LIQUIDATED DAMAGES, THE PARTIES ACKNOWLEDGE AND AGREE THAT SUCH DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE AND THAT SUCH PAYMENT IS INTENDED TO BE A REASONABLE APPROXIMATION OF THE AMOUNT OF SUCH DAMAGES AND NOT A PENALTY.

SECTION 10
TRANSFER

10.1. Restriction of Assignments. Except as otherwise provided in this Section 10, neither party may assign this Agreement without (i) the other party’s prior written consent, such consent not to be unreasonably delayed, conditioned or withheld, it being understood that refusal to consent to the assignment of the Agreement to a Person that does not own or control the operation of the Capacity Facility shall not be deemed to be unreasonable, and (ii) the prior approval of the Board. Any assignment in violation of this provision shall be void.

10.2. Generator’s Assignment Without Consent. Notwithstanding the foregoing or anything expressed or implied herein to the contrary, Generator may, without the prior written consent of Utility and with notice to the Board, and subject to the last sentence of this Section 10.2, assign this Agreement (i) to a purchaser of all or substantially all of the assets of Generator; or (ii) in connection with the grant of a security interest to any Facility Lender, provided that such security interest does not interfere with the rights of obligations of any party under the Construction Period Security or Delivery Term Security, (iii) in connection with a merger of
Generator with another Person or any other transaction resulting in a direct or indirect change of control of Generator. The foregoing shall be subject to the provisions that such purchaser, Facility Lender, or the Person surviving such merger, as applicable, (i) agrees in writing to be bound by the terms of this Agreement, including the satisfaction of all obligations through its ownership of or control over the operation of the Capacity Facility, and not from another electric generating facility, (ii) shall not under any circumstances have equity or ownership rights to more than 700 MW of Unforced Capacity from electric generation facilities with standard offer capacity agreements, and (iii) shall provide or maintain Construction Period Security and Delivery Term Security as required under this Agreement. In connection with any assignment of this Agreement by the Generator under this Section, the Generator may transfer, sell, pledge, encumber or collaterally assign its rights under this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, and shall provide notice of such assignment to the Board. Utility agrees to reasonably cooperate with Generator with respect to any such financing and other financial arrangements, including but not limited to entering into with the Facility Lender a customary lender consent agreement, which shall include, but not be limited to, customary terms regarding notice to the Facility Lender of any potential Event of Default hereunder and standstill periods with respect to the exercise of remedies hereunder.

10.3. Utility’s Assignment Without Consent. Notwithstanding the foregoing or anything expressed or implied herein to the contrary, Utility may, without the prior written consent of Generator and with notice to the Board, assign this Agreement (i) to a purchaser of all or substantially all of the assets of Utility; or (ii) in connection with a merger of Utility with another Person or any other transaction resulting in a change of control of Utility; provided that such purchaser, Affiliate or the Person surviving such merger, as applicable, agrees in writing to be bound by the terms of this Agreement.

10.4. Assumption by Assignee; No Release from Liabilities. Any permitted assignee or transferee of a party’s interest in this Agreement shall assume all existing and future obligations of such party to be performed under this Agreement. Whether or not prior written consent to an assignment is required hereunder, the assignor shall give notice to the other party and to the Board promptly after a permitted assignment of this Agreement. Unless otherwise agreed to by the parties and except as set forth in Sections 10.2 and 10.3 above, upon any permitted assignment of this Agreement to an assignee and such assignee’s written assumption of this Agreement, the assigning party shall be released from the performance of its obligations under this Agreement for the period from and after the date of such assignment and assumption; provided, however, that in all other cases, the assigning party shall continue to be bound by this Agreement unless the parties otherwise agree.

SECTION 11
NOTICES

11.1. Effectiveness. Any notice or other communication in respect hereof may be given in any manner set forth below (except that a notice or other communication under Section 7, 8 or
9 will not be effective if given by facsimile transmission or electronic messaging system) to the address or number or in accordance with the electronic messaging system details provided and will be deemed effective as indicated: (i) if in writing and delivered in person or by courier, on the date it is delivered; (ii) if sent by telex, on the date the recipient’s answerback is received; (iii) if sent by facsimile transmission, on the date that transmission is received by a responsible employee of the recipient in legible form (the burden of proving receipt will be on the sender and will not be met by a transmission report generated by the sender’s facsimile machine); (iv) if sent by certified or registered mail (airmail, if overseas) or the equivalent (return receipt requested), on the date that mail is delivered or its delivery is attempted; or (v) if sent by electronic messaging system, on the date that electronic message is received, unless the date of that delivery (or attempted delivery) or that receipt, as applicable, is not a Business Day or that communication is delivered (or attempted) or received, as applicable, after the close of business on a Business Day, in which case that communication will be deemed given and effective on the first following day that is a Business Day.


11.2.1. Addresses for notices or communications to Generator:

Address:

11.2.2. Address for notices or communications to Utility:

Address:

11.2.3. Change of Addresses. Either party may by notice to the other change the address, telex or facsimile number or electronic messaging system details at which notices or other communications are to be given to it.
SECTION 12

RESOLUTION OF DISPUTES

12.1. Notice of Dispute.

12.1.1. In the event of any dispute, controversy or claim arising out of or relating to this Agreement or the breach, termination or validity thereof should arise between the parties (a “Dispute”), a party may declare a Dispute by delivering to the other party a written notice identifying the disputed issue.

12.1.2. If PJM’s RPM is eliminated, then a Dispute shall be deemed to have occurred and both parties shall attempt to develop a replacement for the RCP as provided under Section 12.2.2 to (i) amend this Agreement and (ii) permit Transactions to continue over the remaining Delivery Term, subject to Board approval.

12.1.3. If PJM’s RPM is modified in a material manner such that it adversely affects the performance, calculation or payment of the Transaction, then a party may declare a Dispute and both parties shall attempt to develop a replacement for the RCP as provided under Section 12.2.2 to (i) amend this Agreement and (ii) permit Transactions to continue over the remaining Delivery Term, subject to Board approval.

12.2. Resolution by the Parties

12.2.1. If the Dispute relates to the accuracy of Utility’s calculation of any payment required to be made under this Agreement (a “Calculation Dispute”), then Generator must provide written notice of the Dispute to Utility within ten (10) Business Days of Generator’s receipt of Utility’s calculation of the payment pursuant to Section 2.2., which notice must state the nature of Generator’s disagreement with Utility’s calculation and include all documentation upon which Generator bases its disagreement. Within ten (10) Business Days of Utility’s receipt of a written notice claiming a Calculation Dispute, Utility shall either: (a) notify Generator that Utility agrees the initial calculation was in error and provide a revised calculation of the payment that is the subject of the Calculation Dispute; or (b) provide Generator with the basis of Utility’s determination that the calculation was correct, including all documentation upon which Utility relies. If Generator does not accept Utility’s revised calculation or Utility’s explanation of the original calculation, then, within ten (10) Business Days, executives of both parties shall meet at a mutually agreeable time and place and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the Dispute.

12.2.2. If the Dispute is not a Calculation Dispute, then upon receipt of a written notice claiming a Dispute, executives of both parties shall meet at a mutually agreeable time and place within ten (10) Business Days after delivery of such notice and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the Dispute. In such meetings and exchanges, a party shall have the right to designate as confidential any information that such party offers. No confidential information exchanged in
such meetings for the purpose of resolving a Dispute may be used by a party in litigation against
the other party.

12.2.3. Any correction to a calculation upon which the parties agree to resolve
the Calculation Dispute, shall be payable within ten (10) Business Days of such resolution plus
interest at the Interest Rate.

12.2.4. If the parties are unable to resolve a Dispute between themselves
pursuant to Section 12.2, then the Dispute will be submitted to the Board for resolution.

12.3. Effect of Dispute

The pendency of a Dispute shall not suspend, either: (a) the obligation of the parties to
perform their obligations under this Agreement, including the obligation to make payments, prior
to a Termination Date; or (b) the effectiveness of a notice of an Event of Default under Section
9.1.1 or a notice designating an Early Termination Date under Section 9.1.2.

SECTION 13
MISCELLANEOUS

13.1. Entire Agreement. This Agreement constitutes the entire agreement and
understanding of the parties with respect to its subject matter and supersedes all oral
communication and prior writings with respect thereto.

13.2. Amendments. No amendment, modification or waiver in respect hereof will be
effective unless (i) in writing (including a writing evidenced by a facsimile transmission) and
executed by each of the parties or confirmed by an exchange of telexes or electronic messages on
an electronic messaging system and (ii) until approved by the Board.

13.3. Remedies Cumulative. Except as provided in this Agreement, the rights, powers,
remedies and privileges provided in this Agreement are cumulative and not exclusive of any
rights, powers, remedies and privileges provided by law.

13.4. Counterparts. This Agreement (and each amendment, modification and waiver in
respect of it) may be executed and delivered in counterparts (including by facsimile
transmission), each of which will be deemed an original.

13.5. Execution of Clearing Requirement. In the event the Transaction is determined to
be subject to any requirement that it be executed or cleared pursuant to the Commodities Futures
Trading Commission or similar exchange or multiparty platform, the parties agree to (i)
cooperate to preserve and enforce the provisions of this Agreement and (ii) consent to any
commercially reasonable margin or other requirements.

13.6. No Waiver of Rights. A failure or delay in exercising any right, power or
privilege in respect hereof will not be presumed to operate as a waiver, and a single or partial
exercise of any right, power or privilege will not be presumed to preclude any subsequent or
further exercise, of that right, power or privilege or the exercise of any other right, power or privilege.

13.7. **Relationship of the Parties.** The parties acknowledge that the relationship between Utility and Generator is an independent contractual relationship and nothing in this Agreement shall create any joint venture, partnership or principal/agent relationship between Utility and Generator. Neither Utility nor Generator shall have any right, power or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other party in any way.

13.8. **Governing Law and Jurisdiction**

13.8.1. **Governing Law.** This Agreement will be governed by and construed in accordance with the substantive law of the State of New Jersey, without regard to the application of such state’s laws relating to conflicts of laws.

13.8.2. **Jurisdiction.** With respect to any suit, action or proceedings relating hereto (“Proceedings”), each party irrevocably: (i) submits to the exclusive jurisdiction of the courts of the State of New Jersey; and (ii) waives any objection which it may have at any time to the laying of venue of any Proceedings brought in any such court, waives any claim that such Proceedings have been brought in an inconvenient forum and further waives the right to object, with respect to such Proceedings, that such court does not have any jurisdiction over such party. Nothing in this Agreement precludes either party from bringing Proceedings in any other jurisdiction in order to enforce any judgment obtained in any Proceedings referred to in the preceding sentence.

13.9. **Waiver of Immunities.** Each party irrevocably waives, to the fullest extent permitted by Applicable Law, with respect to itself and its revenues and assets (irrespective of their use or intended use), all immunity on the grounds of sovereignty or other similar grounds from (i) suit, (ii) jurisdiction of any court, (iii) relief by way of injunction, order for specific performance or for recovery of property, (iv) attachment of its assets (whether before or after judgment) and (v) execution or enforcement of any judgment to which it or its revenues or assets might otherwise be entitled in any Proceedings in the courts of any jurisdiction and irrevocably agrees, to the extent permitted by Applicable Law, that it will not claim any such immunity in any Proceedings.

13.10. **Severability.** The invalidity or unenforceability of any provision of this Agreement shall not affect the other provisions hereof. If any provision of this Agreement is held to be invalid, the scope of the rights and duties created thereby shall be reduced by the smallest extent necessary to conform such provision to applicable law, preserving to the greatest extent the intent of the parties to create such rights and duties as set out herein. If necessary to preserve the intent of the parties hereto and the prevailing economic balance between the parties at the Effective Date, the parties shall negotiate in good faith to amend this Agreement, adopting a substitute provision that is legally binding and enforceable for the one deemed invalid or unenforceable, provided that such amended Agreement shall be subject to Board approval.
13.11. Waiver of Jury Trial. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED. EACH PARTY ACKNOWLEDGES THAT IT AND THE OTHER PARTY HAVE BEEN INDUCED TO ENTER HEREINTO BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION.

IN WITNESS WHEREOF the parties have executed this Agreement as of the date first above written.

By: __________________________
Name: _______________________
Title: _______________________
Company: ____________________

By: __________________________
Name: _______________________
Title: _______________________
Company: ____________________
ATTACHMENT A

DESCRIPTION OF THE CAPACITY FACILITY

General Technology (such as combined cycle, steam cycle, integrated gasification combined cycle, nuclear, wind, etc.): ________________________________

Size (net MW of installed capacity): ________________________________

Full Load Heat Rate (BTU/kWh, HHV, summer rating): ________________________________

Primary Fuel (such as coal, gas, residual oil, distillate oil): ________________________________

Secondary Fuel (if applicable): ________________________________

Number and Configuration of Prime Movers (such as two industrial frame gas turbines plus one steam turbine generator, single pulverized fuel boiler plus steam turbine generator, two circulating fluidized bed boiler plus steam turbine generator, nuclear plant uprate, twenty onshore wind turbines): ________________________________

Location (town or city, county, state): ________________________________

Owner(s) and Ownership Percentage(s): ________________________________
ATTACHMENT B

FORM OF CONSTRUCTION PERIOD SECURITY LETTER OF CREDIT

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

Reference Number: ______________________  Date: __________________

AMOUNT: USD ______________________

EXPIRY: ____________________________

BENEFICIARY: ______________________  APPLICANT: ______________________

[UTILITY]  [GENERATOR]

[ADDRESS OF UTILITY]  [ADDRESS OF GENERATOR]

Ladies and Gentlemen:

[BANK] (“we” or the “Bank”) hereby establish our Irrevocable Nontransferable Standby Letter of Credit No. _________ (this “Letter of Credit”) in your favor in the amount of XXX AND XX/100 Dollars ($ _____ ) (the “Available Amount”), effective immediately and expiring at 5:00 p.m., Eastern Prevailing Time, on the Expiration Date (as hereinafter defined).

This Letter of Credit expires and shall be of no further force or effect upon the close of business on ______________ or, if such day is not a Business Day (as hereinafter defined), on the next [preceding] [succeeding] Business Day (the “Expiration Date”); provided, however, that this Letter of Credit shall automatically be extended for additional one-year terms unless we provide written notice to you, by certified mail return receipt requested or overnight delivery, at least 60 days prior to the then current Expiration Date. For the purposes hereof, “Business Day” shall mean any day on which commercial banks are not authorized or required to close in New York, NY.

Subject to the terms and conditions herein, funds under this Letter of Credit are available to Beneficiary by presentation of your sight draft(s) drawn on the Bank of the following, on or prior to 5:00 p.m. Eastern Prevailing Time, on or prior to the Expiration Date:

1. The original of this Letter of Credit and all amendments (or photocopy of the original for partial drawings); and

2. The Drawing Certificate issued in the form of Exhibit A attached hereto and which forms an integral part hereof, duly completed (including a Statement of Damages, in the
case of a drawing pursuant to paragraph 1.A, 1.B, 1.C or 1.D thereof) and purportedly bearing the signature of an executive officer or director of the Beneficiary.

Notwithstanding the foregoing, any drawing hereunder may be requested by transmitting the requisite documents as described above to the Bank by facsimile at ______________ or such other number as specified from time-to-time by the Bank.

The facsimile transmittal shall be deemed delivered when received, provided, however, that the original documents referenced in paragraphs 1 and 2 above and the sight draft referenced above are received by the Bank prior to 5:00 p.m. Eastern Prevailing Time on the third Business Day following receipt of such facsimile transmittal.

Partial drawing of funds shall be permitted under this Letter of Credit, and this Letter of Credit shall remain in full force and effect with respect to any continuing balance; provided that, the Available Amount shall be reduced by the amount of each such drawing.

This Letter of Credit may be cancelled upon written notice from the Beneficiary, requesting that the Letter of Credit be cancelled, accompanied by the original of this Letter of Credit and all amendments.

This Letter of Credit is not transferable or assignable. Any purported transfer or assignment shall be void and of no force or effect.

Banking charges shall be the sole responsibility of the Applicant.

This Letter of Credit sets forth in full our obligations and such obligations shall not in any way be modified, amended, amplified or limited by reference to any documents, instruments or agreements referred to herein, except only the attachment referred to herein; and any such reference shall not be deemed to incorporate by reference any document, instrument or agreement except for such attachment.

The Bank engages with the Beneficiary that Beneficiary’s drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored if presented to the Bank on or before the Expiration Date.

Except so far as otherwise stated, this Letter of Credit is subject to the International Standby Practices ISP98 (also known as International Chamber of Commerce Publication No. 590), or revision currently in effect (the “ISP”). As to matters not covered by the ISP, the laws of the State of New York, without regard to the principles of conflicts of laws thereunder (other than Section 5-1401 of the General Obligations Law of the State of New York), shall govern all matters with respect to this Letter of Credit.

-30-
AUTHORIZED SIGNATURE for Issuer

(Name)

Title:
EXHIBIT A

DRAWING CERTIFICATE

TO [ISSUING BANK NAME]

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

No.__________________

DRAWING CERTIFICATE

Bank

Bank Address

Subject: Irrevocable Nontransferable Standby Letter of Credit

Reference Number: ________________________________

The undersigned executive officer or director of [UTILITY] (the “Beneficiary”), hereby
certifies under penalty of perjury to [ISSUING BANK NAME] (the “Bank”), and
[GENERATOR] (the “Applicant”), with reference to Irrevocable Nontransferable Standby Letter
of Credit No.__________________, dated__________________ (the Letter of Credit”), issued by the Bank in favor
of the Beneficiary, as follows as of the date hereof:

1. The Beneficiary is entitled to payment of an amount equal to $_________ under
that certain Standard Offer Capacity Agreement between Applicant and Beneficiary dated as of
_______________, 20___ (the “Agreement”) for the following reason(s) [check applicable
provision]:

[ ]A. An “Early Termination Date” (as defined in the Agreement) has occurred or been
designated as a result of an “Event of Default” (as defined in the Agreement) or Termination
Event for which the Applicant owes a termination payment, and the true calculation of such
payment amount is set forth in detail in the attached Statement of Damages.

[ ]B. (i) (A) The Bank has heretofore provided written notice to the Beneficiary of the
Bank’s intent not to renew the Letter of Credit following the present Expiration Date thereof or
(B) the Letter of Credit will expire in fewer than 30 days from the date hereof, and (ii) the
Applicant is required to but has not provided Beneficiary alternative Construction Period
Security (as defined in the Agreement). The Applicant will hold the proceeds of the Letter of
Credit as cash collateral for any and all amounts owing to the Applicant under the Agreement until such time as it is entitled to payment of such amount pursuant to the Agreement.

2. Based upon the foregoing, the Beneficiary hereby makes demand under the Letter of Credit for payment of _____________________________ U.S. DOLLARS AND _____/100ths (U.S.$_________), which amount does not exceed (i) the amount set forth in paragraph 1 above and (ii) the Available Amount under the Letter of Credit as of the date hereof.

3. Funds paid pursuant to the provisions of the Letter of Credit shall be wire transferred to the Beneficiary in accordance with the following instructions:

___________________________________

___________________________________

___________________________________

 Unless otherwise provided herein, capitalized terms which are used and not defined herein shall have the meaning given each such term in the Letter of Credit.

IN WITNESS WHEREOF, this Certificate has been duly executed and delivered, [together with the attached Statement of Damages,] on behalf of the Beneficiary by its undersigned executive officer or director as of this ____ day of ___________ , ___.

Beneficiary: [UTILITY]

By: ______________________________
Name: ____________________________
Title: ______________________________

Copy to:

[GENERATOR]

[ADDRESS OF GENERATOR]

[ATTACH STATEMENT OF DAMAGES, IF APPLICABLE]
STATEMENT OF DAMAGES

For the reason(s) indicated in the Drawing Certificate to which this Statement of Damages is attached, and which this Statement of Damages is an integral part of, the Beneficiary certifies (i) that it has calculated that $ (or a greater amount) is presently due and owing to Beneficiary on account of [a continuing “Event of Default”] [a Termination Event] [an “Early Termination Date”] (as defined in the Agreement), calculated as set forth in detail below, and (ii) such calculation is made in accordance with Sections 2.3.4 and 9 of the Agreement.

[INSERT DETAILED CALCULATION OF DAMAGES]
FORM OF CASH ESCROW AGREEMENT FOR CONSTRUCTION PERIOD SECURITY

Pursuant to this Escrow Agreement ("Agreement") dated [______], [UTILITY] (the "Secured Party") and [GENERATOR] (the "Depositor") hereby establish an Escrow Account (the "Account") with __________ (the "Agent") (the Secured Party, Depositor and Agent hereafter referred to individually as a "Party" and collectively as the "Parties"), to be maintained and administered for the purposes described in Schedule I attached hereto in accordance with the following terms and conditions:

The funds and/or property described on Schedule I attached hereto and incorporated herein (the "Cash Deposit") will be deposited in the Account upon delivery thereof to the Agent in the manner and at the time(s) specified in the said Schedule I. The Agent is hereby authorized and directed by the Secured Party and the Depositor, as their escrow agent, to hold, deal with and dispose of the Cash Deposit as provided in the Instructions set forth in Schedule II attached hereto and incorporated herein; subject to and in accordance with, however, the terms and conditions set forth in the following paragraphs of this Agreement, which in all events shall govern and control over any contrary or inconsistent provisions contained in Schedules I or II attached hereto.

Terms not defined but used herein and in Schedules I, II, III and IV hereto will have the meanings given to them in the Standard Offer Capacity Agreement (the "SOCA"), dated as of [______], 20__ between Secured Party and Depositor.

1. Agent’s Duties. Agent’s duties and responsibilities shall be limited to those expressly set forth in this Agreement, and Agent shall not be subject to, or obliged to recognize, any other agreement between any or all of the other Parties or any other persons, even though reference thereto may be made herein; provided, however, this Agreement may be amended at any time or times by an instrument in writing signed by all of the Parties. Agent shall not be subject to or obligated to recognize any notice, direction or instruction of any or all of the Parties or of any other person, except as expressly provided for and authorized in Schedule II, and in performing any duties under this Agreement, the Agent shall not be liable to any Party for consequential damages (including, without limitation lost profits), losses or expenses, except and to the extent attributable to any gross negligence or willful misconduct on the part of the Agent.

2. Court Orders or Process. If any controversy arises between the Parties, or with any other party, concerning the subject matter of this Agreement, its terms or conditions, Agent will not be required to determine and/or resolve the controversy or to take any action regarding it. Agent may hold all documents and funds and may wait for settlement of any such controversy by final appropriate legal proceedings or other means as, in Agent’s discretion, Agent may require as evidence of final settlement, despite what may be set forth elsewhere in this Agreement. In such event, Agent will not be liable for interest or damage. Agent is authorized, in its sole discretion, to comply with orders issued or process entered by any court with respect to the Account, the Cash Deposit or this Agreement, without determination by the Agent of such court’s jurisdiction in the matter. If any part of the Cash Deposit are at any time attached,
garnished, or levied upon under any court order, or in case the payment, assignment, transfer, conveyance or delivery of any such property shall be stayed or enjoined by any court order, or in case any order, judgment or decree shall be made or entered by any court affecting such property or any part thereof, then in any such event, Agent is authorized, in its sole discretion, to rely upon and comply with any such order, writ, judgment or decree which it is advised by legal counsel of its own choosing is binding upon it; and if Agent complies with any such order writ, judgment or decree, it shall not be liable to either the Secured Party or the Depositor or to any other person, firm or corporation by reason of such compliance, even though such order, writ, judgment or decree may be subsequently reversed, modified, annulled, set aside or vacated.

3. Agent’s Actions and Reliance. Agent shall not be personally liable for any act taken or omitted by it hereunder if taken or omitted by it in good faith and in the exercise of its own best judgment, except and to the extent any such act or omission constitutes gross negligence or willful misconduct on the part of the Agent. Agent shall also be fully protected in relying upon any written notice, instruction, direction, certificate or document provided to it under and pursuant to this Agreement that in good faith it believes to be genuine, including written instructions from the Secured Party or the Depositor in the form of the attached Exhibit(s), if any.

4. Collections. Unless otherwise specifically indicated in Schedule II, Agent shall proceed as soon as practicable to collect any checks, interest due, matured principal or other collection items with respect to Cash Deposit at any time deposited in the Account. All such collections shall be subject to the usual collection procedures regarding items received by Agent for deposit or collection. Agent shall not be responsible for any collections with respect to the Cash Deposit if Agent is not registered as record owner thereof or otherwise is not entitled to request or receive payment thereof as a matter of legal or contractual right. All collection payments or receipts shall be deposited to the respective Account, except as otherwise provided in Schedule II. Agent shall not be required or have a duty to notify anyone of any payment or maturity under the terms of any instrument, security or obligation deposited in the Account, nor to take any legal action to enforce payment of any check, instrument or other security deposited in the Account. The Account is a safekeeping escrow account, and no interest shall be paid by Agent on any money deposited or held therein, except as provided in Section 6 hereof.

5. Agent Responsibility. Agent shall not be responsible or liable for the sufficiency or accuracy of the form, execution, validity or genuineness of documents, instruments or securities now or hereafter deposited in the Account, or of any endorsement thereon, or for any lack of endorsement thereon, or for any description therein. Registered ownership of or other legal title to Cash Deposit deposited in the Account shall be maintained in the name of Agent, or its nominee, only if expressly provided in Schedule II. Agent may maintain qualifying Cash Deposit in a Federal Reserve Bank or in any registered clearing agency as Agent may select, and may register such deposited Cash Deposit in the name of Agent or its agent or nominee on the records of such Federal Reserve Bank or such registered clearing agency or a nominee of either. Agent shall not be responsible or liable in any respect on account of the identity, authority or rights of the persons executing or delivering or purporting to execute or deliver any such document, security or endorsement or this Agreement.
6. Investments. All monies held in the Account shall be invested by Agent in a triple “A” rated money market fund or in such other investments as may be provided for in Schedule III. The shares of the funds are not deposits or obligations of, or guaranteed by any bank, nor are they insured by the Federal Deposit Insurance Corporation, the Federal Reserve Board or any other agency. The investment in such fund or other investments may involve investment risk, including possible loss of principal. The Agent shall not be liable for losses, penalties or charges incurred upon any sale or purchase of any such investment. All interest, dividends, distributions and other accretions to the Cash Deposit shall [become part of the Cash Deposit] [be disbursed pursuant to Schedule III]. All entities entitled to receive interest or income from the Account will provide Agent with a W-9 or W-8 IRS tax form prior to the disbursement of interest or income. A statement of citizenship will be provided if requested by Agent.

7. Notices/Directions to Agent. Notices and directions to Agent from the Secured Party or the Depositor, or from other persons authorized to give such notices or directions as expressly set forth in Schedule II, shall be in writing and signed by an authorized representative as identified pursuant to Schedule II, and shall not be deemed to be given until actually received by Agent’s employee or officer who administers the Account. Agent shall not be responsible or liable for the authenticity or accuracy of notices or directions properly given hereunder if the written form and execution thereof on its face purports to satisfy the requirements applicable thereto as set forth in Schedule II, as determined by Agent in good faith without additional confirmation or investigation.

8. Books and Records. Agent shall maintain books and records regarding its administration of the Account, and the deposit, investment, collections and disbursement or transfer of Cash Deposit, shall retain copies of all written notices and directions sent or received by it in the performance of its duties hereunder, and shall afford each of the Secured Party and the Depositor reasonable access, during regular business hours, to review and make photocopies (at Depositor’s cost) of the same.

9. Disputes Among Depositors and/or Third Parties. In the event Agent is notified of any dispute, disagreement or legal action between the Secured Party and the Depositor and/or any third parties, relating to or arising in connection with the Account, the Cash Deposit or the performance of the Agent’s duties under this Agreement, the Agent shall be authorized and entitled, subject to Section 2 hereof, to suspend further performance hereunder, to retain and hold the Cash Deposit then in the Account, and to take no further action with respect thereto until the matter has been fully resolved, as evidenced by written notification signed by the Secured Party and the Depositor and any other parties to such dispute, disagreement or legal action.

10. Notice by Agent. Any notices which Agent is required or desires to give hereunder to the Secured Party or the Depositor shall be in writing and may be given by mailing the same to the address indicated below opposite the signature of such Party (or to such other address as said Party may have theretofore substituted therefore by written notification to Agent), by United States certified or registered mail, postage prepaid, by reputable overnight courier service, or by facsimile, so long as receipt of any such facsimile is confirmed. For all purposes hereof, any notice so mailed shall be as effective as though served upon the person of the Party to whom it was mailed on the third (3rd) business day after the time it is deposited in the United...
States mail by Agent, properly addressed and with postage prepaid, whether or not such Party thereafter actually receives such notice. Notice given in any other manner shall be effective upon receipt. Whenever under the terms hereof the time for Agent’s giving a notice or performing an act falls upon a Saturday, Sunday, or holiday, such time shall be extended to the next business day.

11. Agent Compensation and Expenses. Agent shall be paid a fee for its services as set forth on Schedule IV attached hereto and incorporated herein, which shall be subject to increase upon notice sent to the Secured Party and the Depositor, and reimbursed for its reasonable costs and expenses incurred. The Depositor will pay all Agent’s usual charges and Agent may deduct such sums from the funds deposited. If Agent’s fees, reasonable costs or expenses provided for herein are not promptly paid when due, and if there is no cash or insufficient cash in the Account to pay the same, then upon thirty (30) days’ prior written notice to the Secured Party and the Depositor, Agent may sell such portion of the Cash Deposit held in the Account as necessary and reimburse itself therefor from the proceeds of such sale. In the event that the conditions of this Agreement are not promptly fulfilled; or if Agent renders any service not provided for in this Agreement; or if the Secured Party and the Depositor request a substantial modification of its terms; or if any controversy arises, or if Agent is made a party to or intervenes in any litigation pertaining to this escrow or its subject matter or, in the exercise of its business judgment, finds it necessary to consult with counsel regarding the same, then in any such case Agent shall be reasonably compensated for such extraordinary services and reimbursed for all costs, attorney’s fees (including reasonably allocated costs of in-house counsel), and expenses reasonably incurred by Agent in connection with such default, delay, controversy or litigation, and Agent shall have the right to retain all documents and/or other things of value at any time held by Agent in this escrow until such compensation, fees, costs, and expenses are paid. The Depositor promise to pay these sums upon demand. The Depositor and its respective successors and assigns agree to indemnify and hold Agent harmless against any and all losses, claims, damages, liabilities, and expenses, including reasonable costs of investigation, counsel fees (including reasonably allocated costs of in-house counsel) and disbursements that may be imposed on Agent or incurred by Agent in connection with the performance of its duties under this Agreement. Agent shall have a first lien on the Cash Deposit for such compensation and expenses.

12. Agent Resignation. It is understood that Agent reserves the right to resign at any time by giving written notice of its resignation, specifying the effective date thereof, to the Secured Party and the Depositor. Within thirty (30) days after receiving the aforesaid notice, the Secured Party and the Depositor agree to appoint a successor escrow agent to which Agent may transfer the Cash Deposit then held in the Account, less its unpaid fees, costs and expenses. If a successor escrow agent has not been appointed and has not accepted such appointment by the end of such thirty (30) day period, Agent may apply to a court of competent jurisdiction for the appointment of a successor escrow agent, and the costs, expenses and reasonable attorney’s fees which Agent incurs in connection with such a proceeding shall be paid by the Secured Party and the Depositor.

13. Escrow Termination. If this Agreement shall not have previously terminated, then it shall terminate on [___________], as provided in Schedule II, at which time the Cash
Deposit then held in the Account, less Agent’s unpaid fees, costs and expenses shall be distributed in the following manner:

[____________________________________________________]

14. Governing Law. This Agreement shall be construed, enforced, and administered in accordance with the laws of the State of [New Jersey].

15. Automatic Succession. Any company into which the Agent may be merged or with which it may be consolidated, or any company to whom Agent may transfer a substantial amount of its Escrow business, shall be the Successor to the Agent without the execution or filing of any paper or any further act on the part of any of the Parties, anything herein to the contrary notwithstanding.

16. Disclosure: The Parties hereby agree not to use the name of [insert name of Agent] to imply an association with the transaction other than that of a legal escrow agent.

17. Counterparts: This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which, when taken together, shall constitute and be one and the same instrument. The exchange of copies of this Agreement and of signature pages by facsimile transmission shall constitute effective execution and delivery of this Agreement as to the Parties and may be used in lieu of the original Agreement for all purposes. Signatures of the Parties transmitted by facsimile shall be deemed to be their original signatures for all purposes.

The undersigned Agent hereby agrees to hold, deal with and dispose of the Cash Deposit at any time deposited to the Account in accordance with the foregoing Agreement.

[Signature page follows]
IN WITNESS WHEREOF, the undersigned have affixed their signatures and hereby adopt as part of this instrument Schedules I, II, III and IV, which are incorporated by reference.

<table>
<thead>
<tr>
<th>SECURED PARTY:</th>
<th>DEPOSITOR:</th>
</tr>
</thead>
<tbody>
<tr>
<td>By:</td>
<td>By:</td>
</tr>
<tr>
<td>Its:</td>
<td>Its:</td>
</tr>
<tr>
<td>(Address)</td>
<td>(Address)</td>
</tr>
<tr>
<td>(City, State and Zip Code)</td>
<td>(City, State and Zip Code)</td>
</tr>
<tr>
<td>(Telephone)</td>
<td>(Telephone)</td>
</tr>
<tr>
<td>(Facsimile Number)</td>
<td>(Facsimile Number)</td>
</tr>
<tr>
<td>Tax I.D.</td>
<td>Tax I.D.</td>
</tr>
</tbody>
</table>

Notices to Agent shall be sent to:

[Name]
[Address]
[City, State, Zip]

With Fax Copy to:
[Name]
[Facsimile Number]
SCHEDULE I
TO CASH ESCROW AGREEMENT

PURPOSE AND MANNER OF DEPOSITS

Credit Support provided by Depositor in the form of Cash under the SOCA, all investments of such Cash, and all proceeds of such investments.

All Credit Support in the form of Cash provided by the Depositor shall be deposited in the Account promptly upon receipt by the Agent.

Instructions for transfer of funds into the Account:

_____________________

_____________________

_____________________

_____________________
SCHEDULE II
TO CASH ESCROW AGREEMENT

INSTRUCTIONS OF DEPOSITORS

1. Upon written notice signed by the Secured Party to the Agent that one or more of the following events has occurred, Agent shall withdraw Cash in the amount specified in such notice from the Account (as described on Schedule I) and shall transfer such Cash in accordance with the Secured Party’s instructions.

   (d) An Early Termination Date (as defined in the SOCA) has occurred or been designated as a result of an Event of Default or a Termination Event (as defined in the Agreement) and a specified amount of the Termination Payment (as defined in the SOCA) owed by the Depositor to the Secured Party remains outstanding.

2. Upon written notice signed by both the Secured Party and the Depositor that the Depositor has replaced a specified amount of Cash in the Account with a Letter of Credit (as defined in the SOCA), the Agent shall withdraw such amount of Cash from Depositor’s Subaccount and transfer such Cash in accordance with the Depositor’s instructions.

3. The Agent shall liquidate such Cash Deposit from the Account as may be necessary to meet the withdrawal instructions under paragraphs 1 through 2 of this Schedule II.

7. Authorized persons referred to in Sections 1 and 7 of the Agreement are as specified below, as such names may be amended from time to time by notice to the Agent:

   For Depositor:

   For Secured Party:

   -42-
SCHEDULE III
TO CASH ESCROW AGREEMENT

PERMITTED INVESTMENTS
SCHEDULE IV
TO CASH ESCROW AGREEMENT

SCHEDULE OF FEES FOR SERVICES
AS ESCROW AGENT
ATTACHMENT D

FORM OF DELIVERY TERM SECURITY LETTER OF CREDIT

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

Reference Number: ____________________  Date: ____________________

AMOUNT: USD ______________________

EXPIRY: ____________________________

BENEFICIARY: ________________________  APPLICANT: ________________

[UTILITY] [GENERATOR]

[ADDRESS OF UTILITY] [ADDRESS OF GENERATOR]

Ladies and Gentlemen:

[BANK] ("we" or the "Bank") hereby establish our Irrevocable Nontransferable Standby Letter of Credit No. __________ (this “Letter of Credit”) in your favor in the amount of XXX AND XX/100 Dollars ($ ___________) (the “Available Amount”), effective immediately and expiring at 5:00 p.m., Eastern Prevailing Time, on the Expiration Date (as hereinafter defined).

This Letter of Credit expires and shall be of no further force or effect upon the close of business on ______________ or, if such day is not a Business Day (as hereinafter defined), on the next [preceding] [succeeding] Business Day (the “Expiration Date”); provided, however, that this Letter of Credit shall automatically be extended for additional one-year terms unless we provide written notice to you, by certified mail return receipt requested or overnight delivery, at least 60 days prior to the then current Expiration Date. For the purposes hereof, “Business Day” shall mean any day on which commercial banks are not authorized or required to close in New York, NY.

Subject to the terms and conditions herein, funds under this Letter of Credit are available to Beneficiary by presentation of your sight draft(s) drawn on the Bank of the following, on or prior to 5:00 p.m. Eastern Prevailing Time, on or prior to the Expiration Date:

1. The original of this Letter of Credit and all amendments (or photocopy of the original for partial drawings); and

2. The Drawing Certificate issued in the form of Attachment A attached hereto and which forms an integral part hereof, duly completed (including a Statement of Damages, in the
case of a drawing pursuant to paragraph 1.A, 1.B or 1.C thereof) and purportedly bearing the signature of an executive officer or director of the Beneficiary.

Notwithstanding the foregoing, any drawing hereunder may be requested by transmitting the requisite documents as described above to the Bank by facsimile at ______________ or such other number as specified from time-to-time by the Bank.

The facsimile transmittal shall be deemed delivered when received, provided, however, that the original documents referenced in paragraphs 1 and 2 above and the sight draft referenced above are received by the Bank prior to 5:00 p.m. Eastern Prevailing Time on the third Business Day following receipt of such facsimile transmittal.

Partial drawing of funds shall be permitted under this Letter of Credit, and this Letter of Credit shall remain in full force and effect with respect to any continuing balance; provided that, the Available Amount shall be reduced by the amount of each such drawing.

This Letter of Credit may be cancelled upon written notice from the Beneficiary, requesting that the Letter of Credit be cancelled, accompanied by the original of this Letter of Credit and all amendments.

This Letter of Credit is not transferable or assignable. Any purported transfer or assignment shall be void and of no force or effect.

Banking charges shall be the sole responsibility of the Applicant.

This Letter of Credit sets forth in full our obligations and such obligations shall not in any way be modified, amended, amplified or limited by reference to any documents, instruments or agreements referred to herein, except only the attachment referred to herein; and any such reference shall not be deemed to incorporate by reference any document, instrument or agreement except for such attachment.

The Bank engages with the Beneficiary that Beneficiary’s drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored if presented to the Bank on or before the Expiration Date.

Except so far as otherwise stated, this Letter of Credit is subject to the International Standby Practices ISP98 (also known as International Chamber of Commerce Publication No. 590), or revision currently in effect (the “ISP”). As to matters not covered by the ISP, the laws of the State of New York, without regard to the principles of conflicts of laws thereunder (other than Section 5-1401 of the General Obligations Law of the State of New York), shall govern all matters with respect to this Letter of Credit.
AUTHORIZED SIGNATURE for Issuer

(Name)

Title:
EXHIBIT A

DRAWING CERTIFICATE

TO [ISSUING BANK NAME]

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

No. _______________

DRAWING CERTIFICATE

Bank

Bank Address

Subject: Irrevocable Nontransferable Standby Letter of Credit

Reference Number: _______________

The undersigned executive officer or director of [UTILITY] (the “Beneficiary”), hereby certifies under penalty of perjury to [ISSUING BANK NAME] (the “Bank”), and [GENERATOR] (the “Applicant”), with reference to Irrevocable Nontransferable Standby Letter of Credit No. __________, dated __________ (the “Letter of Credit”), issued by the Bank in favor of the Beneficiary, as follows as of the date hereof:

1. The Beneficiary is entitled to payment of an amount equal to $_________ under that certain Standard Offer Capacity Agreement between Applicant and Beneficiary dated as of __________, 20___ (the “Agreement”) for the following reason(s) [check applicable provision]:

   [ ] A. The Payment Date under Section 2.2 of the Agreement has occurred with respect to such amount, and such amount is presently due and owing under Section 4.1.2 of the Agreement.

   [ ] B. An “Early Termination Date” (as defined in the Agreement) has occurred or been designated as a result of an “Event of Default” (as defined in the Agreement) or Termination Event for which the Applicant owes a termination payment, and the true calculation of such payment amount is set forth in detail in the attached Statement of Damages.

   [ ] C. (i) (A) The Bank has heretofore provided written notice to the Beneficiary of the Bank’s intent not to renew the Letter of Credit following the present Expiration Date thereof or
(B) the Letter of Credit will expire in fewer than 30 days from the date hereof, and (ii) the Applicant is required to but has not provided Beneficiary alternative Delivery Term Security (as defined in the Agreement). The Applicant will hold the proceeds of the Letter of Credit as cash collateral for any and all amounts owing to the Applicant under the Agreement until such time as it is entitled to payment of such amount pursuant to the Agreement.

2. Based upon the foregoing, the Beneficiary hereby makes demand under the Letter of Credit for payment of _____________________________ U.S. DOLLARS AND ________/100ths (U.S.$__________), which amount does not exceed (i) the amount set forth in paragraph 1 above and (ii) the Available Amount under the Letter of Credit as of the date hereof.

3. Funds paid pursuant to the provisions of the Letter of Credit shall be wire transferred to the Beneficiary in accordance with the following instructions:

___________________________________
___________________________________
___________________________________

Unless otherwise provided herein, capitalized terms which are used and not defined herein shall have the meaning given each such term in the Letter of Credit.

IN WITNESS WHEREOF, this Certificate has been duly executed and delivered, [together with the attached Statement of Damages,] on behalf of the Beneficiary by its undersigned executive officer or director as of this ____ day of ___________ , _____.

Beneficiary: [UTILITY]

By: _______________________________
Name: ____________________________
Title: _____________________________

Copy to:

[GENERATOR]

[ADDRESS OF GENERATOR]

[ATTACH STATEMENT OF DAMAGES, IF APPLICABLE]
STATEMENT OF DAMAGES

For the reason(s) indicated in the Drawing Certificate to which this Statement of Damages is attached, and which this Statement of Damages is an integral part of, the Beneficiary certifies (i) that it has calculated that $ (or a greater amount) is presently due and owing to Beneficiary on account of [a failure to make a payment under Section 4.1.2 of the Agreement] [an “Early Termination Date”] (as defined in the Agreement), calculated as set forth in detail below, and (ii) such calculation is made in accordance with Sections [2.3.4 and 9 of the Agreement].

[INSERT DETAILED CALCULATION OF DAMAGES]
Pursuant to this Escrow Agreement ("Agreement") dated [________], [UTILITY] (the “Secured Party”) and [GENERATOR] (the “Depositor”) hereby establish an Escrow Account (the “Account”) with ____________ (the “Agent”) (the Secured Party, Depositor and Agent hereafter referred to individually as a “Party” and collectively as the “Parties”), to be maintained and administered for the purposes described in Schedule I attached hereto in accordance with the following terms and conditions:

The funds and/or property described on Schedule I attached hereto and incorporated herein (the “Cash Deposit”) will be deposited in the Account upon delivery thereof to the Agent in the manner and at the time(s) specified in the said Schedule I. The Agent is hereby authorized and directed by the Secured Party and the Depositor, as their escrow agent, to hold, deal with and dispose of the Cash Deposit as provided in the Instructions set forth in Schedule II attached hereto and incorporated herein; subject to and in accordance with, however, the terms and conditions set forth in the following paragraphs of this Agreement, which in all events shall govern and control over any contrary or inconsistent provisions contained in Schedules I or II attached hereto.

Terms not defined but used herein and in Schedules I, II, III and IV hereto will have the meanings given to them in the Standard Offer Capacity Agreement (the “SOCA”), dated as of [________], 20__ between the Secured Party and Depositor.

1. Agent’s Duties. Agent’s duties and responsibilities shall be limited to those expressly set forth in this Agreement, and Agent shall not be subject to, or obliged to recognize, any other agreement between any or all of the other Parties or any other persons, even though reference thereto may be made herein; provided, however, this Agreement may be amended at any time or times by an instrument in writing signed by all of the Parties. Agent shall not be subject to or obligated to recognize any notice, direction or instruction of any or all of the Parties or of any other person, except as expressly provided for and authorized in Schedule II, and in performing any duties under this Agreement, the Agent shall not be liable to any Party for consequential damages (including, without limitation lost profits), losses or expenses, except and to the extent attributable to any gross negligence or willful misconduct on the part of the Agent.

2. Court Orders or Process. If any controversy arises between the Parties, or with any other party, concerning the subject matter of this Agreement, its terms or conditions, Agent will not be required to determine and/or resolve the controversy or to take any action regarding it. Agent may hold all documents and funds and may wait for settlement of any such controversy by final appropriate legal proceedings or other means as, in Agent’s discretion, Agent may require as evidence of final settlement, despite what may be set forth elsewhere in this Agreement. In such event, Agent will not be liable for interest or damage. Agent is authorized, in its sole discretion, to comply with orders issued or process entered by any court with respect to the Account, the Cash Deposit or this Agreement, without determination by the Agent of such
court’s jurisdiction in the matter. If any Cash Deposit are at any time attached, garnished, or levied upon under any court order, or in case the payment, assignment, transfer, conveyance or delivery of any such property shall be stayed or enjoined by any court order, or in case any order, judgment or decree shall be made or entered by any court affecting such property or any part thereof, then in any such event, Agent is authorized, in its sole discretion, to rely upon and comply with any such order, writ, judgment or decree which it is advised by legal counsel of its own choosing is binding upon it; and if Agent complies with any such order writ, judgment or decree, it shall not be liable to either the Secured Party or the Depositor or to any other person, firm or corporation by reason of such compliance, even though such order, writ, judgment or decree may be subsequently reversed, modified, annulled, set aside or vacated.

3. Agent’s Actions and Reliance. Agent shall not be personally liable for any act taken or omitted by it hereunder if taken or omitted by it in good faith and in the exercise of its own best judgment, except and to the extent any such act or omission constitutes gross negligence or willful misconduct on the part of the Agent. Agent shall also be fully protected in relying upon any written notice, instruction, direction, certificate or document provided to it under and pursuant to this Agreement that in good faith it believes to be genuine, including written instructions from the Secured Party or the Depositor in the form of the attached Exhibit(s), if any.

4. Collections. Unless otherwise specifically indicated in Schedule II, Agent shall proceed as soon as practicable to collect any checks, interest due, matured principal or other collection items with respect to Cash Deposit at any time deposited in the Account. All such collections shall be subject to the usual collection procedures regarding items received by Agent for deposit or collection. Agent shall not be responsible for any collections with respect to any of the Cash Deposit if Agent is not registered as record owner thereof or otherwise is not entitled to request or receive payment thereof as a matter of legal or contractual right. All collection payments or receipts shall be deposited to the respective Account, except as otherwise provided in Schedule II. Agent shall not be required or have a duty to notify anyone of any payment or maturity under the terms of any instrument, security or obligation deposited in the Account, nor to take any legal action to enforce payment of any check, instrument or other security deposited in the Account. The Account is a safekeeping escrow account, and no interest shall be paid by Agent on any money deposited or held therein, except as provided in Section 6 hereof.

5. Agent Responsibility. Agent shall not be responsible or liable for the sufficiency or accuracy of the form, execution, validity or genuineness of documents, instruments or securities now or hereafter deposited in the Account, or of any endorsement thereon, or for any lack of endorsement thereon, or for any description therein. Registered ownership of or other legal title to Cash Deposit deposited in the Account shall be maintained in the name of Agent, or its nominee, only if expressly provided in Schedule II. Agent may maintain qualifying Cash Deposit in a Federal Reserve Bank or in any registered clearing agency as Agent may select, and may register such deposited Cash Deposit in the name of Agent or its agent or nominee on the records of such Federal Reserve Bank or such registered clearing agency or a nominee of either. Agent shall not be responsible or liable in any respect on account of the identity, authority or rights of the persons executing or delivering or purporting to execute or deliver any such document, security or endorsement or this Agreement.
6. Investments. All monies held in the Account shall be invested by Agent in a triple “A” rated money market fund or in such other investments as may be provided for in Schedule III. The shares of the funds are not deposits or obligations of, or guaranteed by any bank, nor are they insured by the Federal Deposit Insurance Corporation, the Federal Reserve Board or any other agency. The investment in such fund or other investments may involve investment risk, including possible loss of principal. The Agent shall not be liable for losses, penalties or charges incurred upon any sale or purchase of any such investment. All interest, dividends, distributions and other accretions to the Cash Deposit shall [become part of the Cash Deposit] [be disbursed pursuant to Schedule III]. All entities entitled to receive interest or income from the Account will provide Agent with a W-9 or W-8 IRS tax form prior to the disbursement of interest or income. A statement of citizenship will be provided if requested by Agent.

7. Notices/Directions to Agent. Notices and directions to Agent from the Secured Party or the Depositor, or from other persons authorized to give such notices or directions as expressly set forth in Schedule II, shall be in writing and signed by an authorized representative as identified pursuant to Schedule II, and shall not be deemed to be given until actually received by Agent’s employee or officer who administers the Account. Agent shall not be responsible or liable for the authenticity or accuracy of notices or directions properly given hereunder if the written form and execution thereof on its face purports to satisfy the requirements applicable thereto as set forth in Schedule II, as determined by Agent in good faith without additional confirmation or investigation.

8. Books and Records. Agent shall maintain books and records regarding its administration of the Account, and the deposit, investment, collections and disbursement or transfer of Cash Deposit, shall retain copies of all written notices and directions sent or received by it in the performance of its duties hereunder, and shall afford each of the Secured Party and the Depositor reasonable access, during regular business hours, to review and make photocopies (at Depositor’s cost) of the same.

9. Disputes Among Depositors and/or Third Parties. In the event Agent is notified of any dispute, disagreement or legal action between the Secured Party and the Depositor and/or any third parties, relating to or arising in connection with the Account, the Cash Deposit or the performance of the Agent’s duties under this Agreement, the Agent shall be authorized and entitled, subject to Section 2 hereof, to suspend further performance hereunder, to retain and hold the Cash Deposit then in the Account, and to take no further action with respect thereto until the matter has been fully resolved, as evidenced by written notification signed by the Secured Party and the Depositor and any other parties to such dispute, disagreement or legal action.

10. Notice by Agent. Any notices which Agent is required or desires to give hereunder to the Secured Party or the Depositor shall be in writing and may be given by mailing the same to the address indicated below opposite the signature of such Party (or to such other address as said Party may have theretofore substituted therefor by written notification to Agent), by United States certified or registered mail, postage prepaid, by reputable overnight courier service, or by facsimile, so long as receipt of any such facsimile is confirmed. For all purposes hereof, any notice so mailed shall be as effective as though served upon the person of the Party to whom it was mailed on the third (3rd) business day after the time it is deposited in the United
States mail by Agent, properly addressed and with postage prepaid, whether or not such Party thereafter actually receives such notice. Notice given in any other manner shall be effective upon receipt. Whenever under the terms hereof the time for Agent’s giving a notice or performing an act falls upon a Saturday, Sunday, or holiday, such time shall be extended to the next business day.

11. Agent Compensation and Expenses. Agent shall be paid a fee for its services as set forth on Schedule IV attached hereto and incorporated herein, which shall be subject to increase upon notice sent to the Secured Party and the Depositor, and reimbursed for its reasonable costs and expenses incurred. The Depositor will pay all Agent’s usual charges and Agent may deduct such sums from the funds deposited. If Agent’s fees, reasonable costs or expenses provided for herein are not promptly paid when due, and if there is no cash or insufficient cash in the Account to pay the same, then upon thirty (30) days’ prior written notice to the Secured Party and the Depositor, Agent may sell such portion of the Cash Deposit held in the Account as necessary and reimburse itself therefor from the proceeds of such sale. In the event that the conditions of this Agreement are not promptly fulfilled; or if Agent renders any service not provided for in this Agreement; or if the Secured Party and the Depositor request a substantial modification of its terms; or if any controversy arises, or if Agent is made a party to or intervenes in any litigation pertaining to this escrow or its subject matter or, in the exercise of its business judgment, finds it necessary to consult with counsel regarding the same, then in any such case Agent shall be reasonably compensated for such extraordinary services and reimbursed for all costs, attorney’s fees (including reasonably allocated costs of in-house counsel), and expenses reasonably incurred by Agent in connection with such default, delay, controversy or litigation, and Agent shall have the right to retain all documents and/or other things of value at any time held by Agent in this escrow until such compensation, fees, costs, and expenses are paid. The Depositor promise to pay these sums upon demand. The Depositor and its respective successors and assigns agree to indemnify and hold Agent harmless against any and all losses, claims, damages, liabilities, and expenses, including reasonable costs of investigation, counsel fees (including reasonably allocated costs of in-house counsel) and disbursements that may be imposed on Agent or incurred by Agent in connection with the performance of its duties under this Agreement. Agent shall have a first lien on the Cash Deposit for such compensation and expenses.

12. Agent Resignation. It is understood that Agent reserves the right to resign at any time by giving written notice of its resignation, specifying the effective date thereof, to the Secured Party and the Depositor. Within thirty (30) days after receiving the aforesaid notice, the Secured Party and the Depositor agree to appoint a successor escrow agent to which Agent may transfer the Cash Deposit then held in the Account, less its unpaid fees, costs and expenses. If a successor escrow agent has not been appointed and has not accepted such appointment by the end of such thirty (30) day period, Agent may apply to a court of competent jurisdiction for the appointment of a successor escrow agent, and the costs, expenses and reasonable attorney’s fees which Agent incurs in connection with such a proceeding shall be paid by the Secured Party and the Depositor.

13. Escrow Termination. If this Agreement shall not have previously terminated, then it shall terminate on [___________], as provided in Schedule II, at which time the Cash
Deposit then held in the Account, less Agent’s unpaid fees, costs and expenses shall be distributed in the following manner:

14. Governing Law. This Agreement shall be construed, enforced, and administered in accordance with the laws of the State of [New Jersey].

15. Automatic Succession. Any company into which the Agent may be merged or with which it may be consolidated, or any company to whom Agent may transfer a substantial amount of its Escrow business, shall be the Successor to the Agent without the execution or filing of any paper or any further act on the part of any of the Parties, anything herein to the contrary notwithstanding.

16. Disclosure: The Parties hereby agree not to use the name of [insert name of Agent] to imply an association with the transaction other than that of a legal escrow agent.

17. Counterparts: This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which, when taken together, shall constitute and be one and the same instrument. The exchange of copies of this Agreement and of signature pages by facsimile transmission shall constitute effective execution and delivery of this Agreement as to the Parties and may be used in lieu of the original Agreement for all purposes. Signatures of the Parties transmitted by facsimile shall be deemed to be their original signatures for all purposes.

The undersigned Agent hereby agrees to hold, deal with and dispose of the Cash Deposit at any time deposited to the Account in accordance with the foregoing Agreement.

[Signature page follows]
IN WITNESS WHEREOF, the undersigned have affixed their signatures and hereby adopt as part of this instrument Schedules I, II, III and IV, which are incorporated by reference.

<table>
<thead>
<tr>
<th>SECURED PARTY:</th>
<th>DEPOSITOR:</th>
</tr>
</thead>
<tbody>
<tr>
<td>By:</td>
<td>By:</td>
</tr>
<tr>
<td>Its:</td>
<td>Its:</td>
</tr>
<tr>
<td>(Address)</td>
<td>(Address)</td>
</tr>
<tr>
<td>(City, State and Zip Code)</td>
<td>(City, State and Zip Code)</td>
</tr>
<tr>
<td>(Telephone)</td>
<td>(Telephone)</td>
</tr>
<tr>
<td>(Facsimile Number)</td>
<td>(Facsimile Number)</td>
</tr>
<tr>
<td>Tax I.D.</td>
<td>Tax I.D.</td>
</tr>
</tbody>
</table>

**Notices to Agent shall be sent to:**

[Name]  
[Address]  
[City, State, Zip]

With Fax Copy to:  
[Name]  
[Facsimile Number]
SCHEDULE I
TO CASH ESCROW AGREEMENT

PURPOSE AND MANNER OF DEPOSITS

Credit Support provided by Depositor in the form of Cash under the SOCA, all investments of such Cash, and all proceeds of such investments.

All Credit Support in the form of Cash provided by the Depositor shall be deposited in the Account promptly upon receipt by the Agent.

Instructions for transfer of funds into the Account:

_____________________

_____________________

_____________________

_____________________

_____________________
SCHEDULE II
TO CASH ESCROW AGREEMENT

INSTRUCTIONS OF DEPOSITORS

1. Upon written notice signed by the Secured Party to the Agent that one or more of the following events has occurred, Agent shall withdraw Cash in the amount specified in such notice from the Account (as described on Schedule I) and shall transfer such Cash in accordance with the Secured Party’s instructions.

    (a) The Depositor has failed to pay an amount presently due and owing under Section 4.1.2 of the Agreement, which amount remains outstanding.

    (b) An Event of Default (as defined in the SOCA) or a Termination Event (as defined in the SOCA) with respect to the Depositor has occurred and is continuing, and the Depositor owes the Secured Party a specified amount in respect of such Event of Default, which amount remains outstanding.

    (c) An Early Termination Date (as defined in the SOCA) has occurred or been designated as a result of an Event of Default or a Termination Event (as defined in the Agreement) and a specified amount of the Termination Payment (as defined in the SOCA) owed by the Depositor to the Secured Party remains outstanding.

2. Upon written notice signed by both the Secured Party and the Depositor that the Depositor has replaced a specified amount of Cash in the Account with a Letter of Credit (as defined in the SOCA), the Agent shall withdraw such amount of Cash from Depositor’s Subaccount and transfer such Cash in accordance with the Depositor’s instructions.

3. The Agent shall liquidate such Cash Deposit from the Account as may be necessary to meet the withdrawal instructions under paragraphs 1 through 2 of this Schedule II.

7. Authorized persons referred to in Sections 1 and 7 of the Agreement are as specified below, as such names may be amended from time to time by notice to the Agent:

   For Depositor:

   For Secured Party:
SCHEDULE III
TO CASH ESCROW AGREEMENT

PERMITTED INVESTMENTS
SCHEDULE IV
TO CASH ESCROW AGREEMENT
ATTACHMENT F

SCHEDULE OF APPROVED STANDARD OFFER CAPACITY PRICES

<table>
<thead>
<tr>
<th>Delivery Year (ending May 31st)</th>
<th>Standard Offer Capacity Price ($/MW-day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td></td>
</tr>
<tr>
<td>2026</td>
<td></td>
</tr>
<tr>
<td>2027</td>
<td></td>
</tr>
<tr>
<td>2028</td>
<td></td>
</tr>
<tr>
<td>2029</td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td></td>
</tr>
<tr>
<td>2031</td>
<td></td>
</tr>
<tr>
<td>2032</td>
<td></td>
</tr>
<tr>
<td>2033</td>
<td></td>
</tr>
</tbody>
</table>
Attachment 1B

Technical Changes Accepted
STANDARD OFFER CAPACITY AGREEMENT
STANDARD OFFER CAPACITY AGREEMENT

This STANDARD OFFER CAPACITY AGREEMENT (“Agreement”), dated as of [__] (“Effective Date”), is entered into by and between [UTILITY], a corporation organized under the law of the state of New Jersey (“Utility”) and [CAPACITY SELLER], a corporation organized under the law of [__] (“Generator”).

WHEREAS, the State of New Jersey has established the Long-Term Capacity Agreement Pilot Program (“LCAPP”) to promote construction of qualified electric generation facilities pursuant to P.L. 2011 c. 9 (the “Act”);

WHEREAS, the Act requires that each Electric Public Utility enter into a standard offer capacity agreement as described in the Act and in a form approved by the New Jersey Board of Public Utilities (“Board”) with eligible generators approved by the Board;

WHEREAS, under the Act, this Agreement shall be irrevocable once the Board issues an order approving this Agreement;

WHEREAS, under the Act, neither the Board nor any other governmental agency of New Jersey shall have the authority (i) to rescind, alter, modify, or repeal this Agreement or an order approving rate recovery of LCAPP costs, (ii) to revalue, re-evaluate, or revise the amount of the LCAPP costs, or (iii) to determine that the LCAPP costs or the revenues to recover the LCAPP costs are unjust or unreasonable;

WHEREAS, Generator has not commenced, and intends to commence, construction of an [__] megawatt (“MW”) electric generation facility, as described in Attachment A, after January 28, 2011 (the “Capacity Facility”);

WHEREAS, Generator is willing to commit to offer and clear Unforced Capacity of the Capacity Facility into each Base Residual Auction conducted by the PJM Interconnection, L.L.C. (“PJM”) for all Delivery Years through the Conclusion Date;

WHEREAS, Generator is willing to commit to offer all the electric energy output and ancillary services of the Capacity Facility into the PJM markets during the Delivery Term;

WHEREAS, Generator’s eligibility and selection to participate in the LCAPP have been approved by the Board;

WHEREAS, this Agreement is in the form approved by the Board;

WHEREAS, Utility is an Electric Public Utility; and

WHEREAS, Generator has caused Construction Period Security to be provided to Utility, dated as of the date hereof, in support of Generator’s obligations under this Agreement.

NOW, THEREFORE, in consideration of the foregoing and mutual terms and conditions set forth herein, and for further good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereby agree as follows:
SECTION 1
DEFINITIONS; RULES OF INTERPRETATION

1.1. Defined Terms. Unless otherwise required by the context in which any term appears, initially capitalized terms used herein have the following meanings:

“Act” means the New Jersey P.L. 2011 c. 9 that establishes the LCAPP.

“Affiliate” means, with respect to any Person, each Person that directly or indirectly controls, is controlled by, or is under common control with such designated Person. For purposes of this definition, “control” (including, with correlative meanings, the terms “controlled by” and “under common control with”), as used with respect to any Person, shall mean (a) the direct or indirect right to cast at least fifty percent (50%) of the votes exercisable at an annual general meeting (or its equivalent) of such Person or, if there are no such rights, ownership of at least fifty percent (50%) of the equity or other ownership interest in such Person, or (b) the right to direct the policies or operations of such Person.

“Agreement” means this Standard Offer Capacity Agreement dated as of [   ], 2011 by and between Utility and Generator.

“Annual Forecasted Peak Demand” means in the case of Utility, its forecasted peak demand and, in the case of another Electric Public Utility, the forecasted peak demand of such other Electric Public Utility, for a given Delivery Year as determined by PJM and published in the most recent PJM Load Forecast Report issued before the start of the Delivery Year.

“Applicable Law” means all legally binding constitutions, treaties, statutes, laws, ordinances, rules, regulations, orders, interpretations, permits, judgments, decrees, injunctions, writs and orders of any Governmental Authority or arbitrator that apply to the LCAPP or any one or both of the parties to this Agreement or the terms hereof.

“Associated Ancillary Services” means the quantity of ancillary services, generally used by PJM to support the reliable operation of its transmission system, associated with the Available Capacity Amount.

“Associated Energy” means the quantity of electrical energy, generally used by PJM to satisfy its load requirements, associated with the Available Capacity Amount

“Automated Clearing House” or “ACH” means an electronic network for financial transactions administered by NACHA-The Electronic Payments Association.

“Available Capacity Amount” means the lesser of: (i) the quantity of Unforced Capacity from the Capacity Facility that is offered by Generator and cleared by PJM in the relevant Base Residual Auction, and (ii) the Awarded Capacity Amount.
“Awarded Capacity Amount” means [ ] MW, the amount of Unforced Capacity for which the Board has approved Generator to enter into standard offer capacity agreements with the Electric Public Utilities pursuant to the Act.

“Awarded Commencement Date” means the first day of the first Delivery Year for which the Board has approved Generator to receive or make payments under standard offer capacity agreements with the Electric Public Utilities pursuant to the Act, which date is June 1, [ ].

“Base Residual Auction” means the primary auction conducted by PJM as part of PJM’s Reliability Pricing Model to secure electrical capacity as necessary to satisfy the capacity requirements imposed under the PJM Reliability Assurance Agreement for the Delivery Year.

“Board” means the New Jersey Board of Public Utilities or any successor agency.

“Business Day” means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday.

“Calculation Dispute” is defined in Section 12.2.1.

“Capacity Facility” means the [ ] MW electric generation facility to be constructed by Generator as further defined in Attachment A.

“Cash” means cash in United States Dollars and any investment of such cash held in escrow.

“Cash Escrow Agreement” means an agreement providing for the receipt, holding (in the United States), investment and disbursement of Cash held in escrow by a Qualified Bank, to provide either Construction Period Security or Delivery Term Security.

“Commencement Date” means the last to occur of: (i) the Awarded Commencement Date; and (ii) the date the Capacity Facility first provides Unforced Capacity to PJM by having previously cleared in a Base Residual Auction.

“Conclusion Date” means May 31, [ ], which date shall not be altered by any delay or change in the Commencement Date or other provision under this Agreement.

“Construction Period” means the period commencing on the Effective Date and concluding on the date the Generator first provides Unforced Capacity to PJM by having previously cleared in a Base Residual Auction.

“Construction Period Security” means (i) a Letter of Credit, substantially in the form of Attachment B, to be provided to the Utility or (ii) Cash held in escrow for the Utility under a Cash Escrow Agreement, substantially in the form of Attachment C to be mutually agreed between the Utility and Generator, in support of the Generator’s obligations during the Construction Period in an amount defined in section 2.3.4.

“Defaulting Party” is defined in Section 9.1.1.
“Delivery Year” means each 12-month period from June 1st through May 31st numbered according to the calendar year in which it ends beginning on the Commencement Date and concluding on the Conclusion Date.

“Delivery Term” means the period commencing with the Commencement Date and concluding on the Conclusion Date.

“Delivery Term Security” means (i) a Letter of Credit, substantially in the form of Attachment D, to be provided to the Utility or (ii) Cash held in escrow for the Utility under a Cash Escrow Agreement, substantially in the form of Attachment E to be mutually agreed between the Utility and Generator, in support of the Generator’s obligations during the Delivery Term in an amount defined in Section 2.3.5.

“Dispute” is defined in Section 12.1.

“Early Termination Date” means the date determined in accordance with Section 9.1.

“Effective Date” is defined in the Preamble hereof.

“EFORd” means a measure calculated by PJM of the probability that an electric power generating unit will not be available due to a forced outage or forced derating when there is a demand on the unit to generate.


“Event of Default” is defined in Section 7.1.

“Facility Lender” means (i) any lender providing construction, interim, long-term, or refinancing debt or equity funds to Generator for the Capacity Facility, (ii) any trustee or agent acting on their behalf, and (iii) any Person providing interest rate protection agreements to hedge any of the foregoing obligations.

“Force Majeure” means an event or circumstance, such as natural catastrophes, terrorism, war, riots, or acts of God, that (i) prevents one party from performing its obligations under this Agreement; (ii) is not within the reasonable control of, or the result of the negligence of, the claiming party; and, (iii) by the exercise of due diligence, the claiming party is unable to overcome or avoid, or cause to be avoided; provided, however, notwithstanding the foregoing, none of the following events or circumstances will constitute Force Majeure: (a) the loss or failure of Generator’s fuel supply, except when caused by Force Majeure; (b) the breakdown of Generator’s plant and/or equipment, except when caused by Force Majeure; and (c) an occurrence or an event that causes an economic hardship to a party.

“Generator” means a developer of an electric power generating facility that the Board has determined to qualify as eligible pursuant to the Act and is named in the Preamble hereof.
“Governmental Authority” means any international, national, federal, provincial, state, municipal, county, regional or local government, administrative, judicial or regulatory entity with jurisdiction over any party hereto, this Agreement, the LCAPP, or PJM, and includes any department, commission, bureau, board, administrative agency or regulatory body of any government.

“Interest Rate” means for any date, the per annum rate of interest equal to the yield on Two-Year U.S. Treasury Notes as may be published in The Wall Street Journal on such day (or if not published on such day the most recent preceding day on which published) plus sixty (60) basis points.

“Illegality” is defined in Section 8.1.1.

“Invalidity of the Act” is defined in Section 8.1.2.

“Letter of Credit” means an irrevocable standby letter of credit provided by a Qualified Bank to provide either Construction Period Security or Delivery Term Security.

“Locational Deliverability Area” or “LDA” means the PJM sub-regions used to calculate Resource Clearing Prices as part of the Reliability Pricing Model.

“Long-Term Capacity Agreement Pilot Program” or “LCAPP” is the program established by P.L. 2011 c. 9 to promote construction of qualified electric generation facilities.

“Month” means a calendar month commencing on the first day of such month and ending on the last day of such month.

“MW” means megawatt.

“NACHA Operating Rules” means the rules issued by NACHA – The Electronic Payments Association for the administration of the Automated Clearing House.

“Non-Defaulting Party” is defined in Section 9.1.1.

“Payment Date” is defined in Section 2.2.

“Person” means an individual, partnership, corporation, limited liability company, joint venture, association, trust, unincorporated organization, Governmental Authority, or other form of entity.

“PJM Interconnection, L.L.C.” or “PJM” means the Regional Transmission Organization that manages the regional, high-voltage electricity grid serving New Jersey and all or parts of other states and, among other things, administers the Reliability Pricing Model, and any successor.

“PJM Market Rules” means the rules, standards, procedures, and practices set forth in the PJM Tariff, PJM Operating Agreements, PJM Reliability Assurance Agreement, PJM Consolidated Transmission Owners Agreement, PJM Manuals, PJM Regional Practices
“PJM Markets” means the capacity, energy, and ancillary services markets administered by PJM.

“Qualified Bank” means a United States commercial bank or similar financial institution that has assets of at least $5 billion and a senior long-term unsecured debt rating of at least “A” by Standard & Poor’s, “A2” by Moody’s Investors Service, or “A” by Fitch Ratings.

“Reliability Pricing Model” or “RPM” means PJM’s capacity-market model that secures capacity on behalf of electric load serving entities to satisfy load obligations not satisfied through the output of electric generation facilities owned by those entities or otherwise secured by those entities through bilateral contracts.

“Resource Clearing Price” or “RCP” means the clearing price expressed in $/MW-day for Unforced Capacity established by the Base Residual Auction for the LDA in which the Capacity facility is located and the applicable Delivery Year as posted by PJM.

“RPM Rules” means the provisions of PJM’s tariffs and agreements accepted by the Federal Energy Regulatory Commission and the provisions of PJM’s manuals governing the Reliability Pricing Model, as in effect from time to time during the term of this Agreement.

“Standard Offer Capacity Price” or “SOCP” means the price for each Delivery Year at which the Board has approved Generator to enter into this Agreement with the Utility pursuant to the Act, which price is listed in Attachment F to this Agreement.

“Termination Date” means the earlier to occur of (i) the Conclusion Date or (ii) the Early Termination Date.

“Termination Event” is defined in Section 8.1.

“Total Annual Forecasted Peak Demand” for a given Delivery Year means the sum of the Annual Forecasted Peak Demands for each Electric Public Utility for such Delivery Year.

“Transaction” means the calculations, payments and payment obligations under Section 4.1 and the related provisions of this Agreement (including without limitation Section 2.1).

“Unforced Capacity” means the capacity of a capacity resource that accounts for the EFORd of that capacity resource and as periodically determined by PJM.

“Unpaid Amounts” owing to any party means, with respect to an Early Termination Date, the amounts that became payable to such party under Section 2.1 in respect of the Transaction on or prior to such Early Termination Date (including amounts not paid by the other party on the ground of the occurrence of an Event of Default, in accordance with Section 2.5) and which remain unpaid as at such Early Termination Date, together with (to the extent permitted under Applicable Law) interest from (and including) the date such amounts were to have been paid to (but excluding) such Early Termination Date, at the Interest Rate. Such amounts of interest will
be calculated on the basis of a 360-day year, daily compounding and the actual number of days elapsed.

“Utility” is defined in the Preamble hereof.

“Utility’s Load Ratio” means the percentage derived by dividing Utility’s Annual Forecasted Peak Demand by Total Annual Forecasted Peak Demand, both for a given Delivery Year, such that the sum of the Utility Load Ratios for the Electric Public Utilities shall always equal 100%.

1.2. Rules of Interpretation

1.2.1. General. Unless otherwise required by the context in which any term appears, (a) the singular includes the plural and vice versa; (b) references to “Articles,” “Sections,” “Schedules,” “Annexes,” “Appendices” or “Exhibits” (if any) are to articles, sections, schedules, annexes, appendices or exhibits hereof; (c) all references to a particular entity or an electricity or gas market price index include a reference to such entity’s or index’s successors and (if applicable) permitted assigns; (d) the words “herein,” “hereof” and “hereunder” refer to this Agreement as a whole and not to any particular Section or subsection hereof; (e) references to this Agreement include a reference to all appendices, annexes, schedules and exhibits hereto, as the same may be amended, modified, supplemented or replaced from time to time; (f) the masculine includes the feminine and neuter and vice versa; (g) the definitions of terms herein shall apply equally to the singular and plural forms of the terms defined; (h) “including” means “including, without limitation” or “including, but not limited to”; and (i) the word “or” is not necessarily exclusive.

1.2.2. Terms Not to be Construed For or Against Either Party. Each term hereof will be construed simply according to its fair meaning and not strictly for or against either party. No term hereof will be construed against a party on the ground that the party is the author of that provision.

1.2.3. Headings. The headings used for the sections and articles hereof are for convenience and reference purposes only and will in no way affect the meaning or interpretation of the provisions hereof.

1.2.4. Rounding. All calculations, including but not limited to RCP, Available Capacity Amount, and Utility Load Ratios, will be rounded to the nearest third decimal place.

SECTION 2
OBLIGATIONS

2.1. General Conditions. Each party will make each payment specified herein to be made by it, including without limitation the payments under Section 2.2, subject to Section 2.5 and the other provisions hereof.
2.2. Calculation and Payment of Transaction Amounts. In the case of the first Delivery Year, no less than thirty (30) calendar days prior to the Awarded Commencement Date and, in the case of each subsequent Delivery Year, no less than thirty (30) calendar days prior to the commencement of such Delivery Year, Utility will provide a statement to Generator of the result of the calculation under Section 4.1 for the Delivery Year, specifying the party obligated to make payments with respect to such Delivery Year, and the monthly amount of such payments, including any correction made under Section 2.19. The party obligated to make payments will make such payments with respect to each Month on or before the last Business Day of the subsequent Month (the “Payment Date”) to the account specified herein in freely transferable funds via electronic funds transfer through a system that provides for final credit no later than one business day after transfer. The system for making such electronic funds transfers may be the ACH, in which case the paying party will originate the ACH credit for receipt the following Business Day. Each party agrees to be bound by the NACHA Operating Rules in connection with payments made via ACH and agrees that the origination of all ACH transactions will comply with applicable provisions of U.S. law. Whenever payments are made via ACH, the receiving party hereby authorizes the paying party to initiate credit entries to the account of the receiving party at the receiving party’s financial institution as set forth in Section 2.6. This authorization will remain in full force and effect until a party has received prior written notice from the other party of its termination, such notice to be provided in such time and in such manner as to afford the party receiving such notice a reasonable opportunity to act on it.

2.3. Obligations of Generator.

2.3.1. Generator shall use all commercially reasonable efforts to cause the Capacity Facility to qualify under the RPM Rules as a capacity resource in an amount no less than the Awarded Capacity Amount for the Base Residual Auction associated with each Delivery Year during the term of this Agreement, commencing upon the Awarded Commencement Date.

2.3.2. Generator shall use all commercially reasonable efforts to cause the Capacity Facility to achieve commercial operation no later than the Commencement Date.

2.3.3. Throughout the Delivery Term, Generator shall:

(a) Cause the Capacity Facility to comply with all obligations of a capacity resource under the RPM Rules, including without limitation the obligations relating to the submission of offers to supply electric energy and ancillary services in PJM markets, and Generator shall bear all costs associated with such compliance, including without limitation all fees and penalties imposed by PJM;

(b) Submit supply offers for an amount of Unforced Capacity no less than the Awarded Capacity Amount from the Capacity Facility in accordance with the RPM Rules in the Base Residual Auction associated with each Delivery Year during the term of this Agreement, such that the Unforced Capacity shall be offered at the lowest commercially reasonable price under the RPM rules;

(c) Submit supply offers from the Capacity Facility for the maximum amount of Associated Energy that the Capacity Facility can provide in the PJM day-ahead energy market.
in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Energy shall be offered at the lowest commercially reasonable price under PJM’s Market Rules;

(d) Submit supply offers from the Capacity Facility for the maximum amount of Associated Ancillary Services that the Capacity Facility can provide in the PJM ancillary services markets in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Ancillary Services shall be offered at the lowest commercially reasonable price under PJM’s Market Rules;

(e) Neither physically nor financially withhold any Unforced Capacity up to the amount of Awarded Capacity, or Associated Energy and Associated Ancillary Services, from the Capacity Facility;

(f) Provide on a timely basis (which, in the case of documentation provided to Generator by PJM, shall mean within five (5) Business Days of Generator’s receipt of such documentation) all documentation required by Utility to make the calculations and notifications required by Sections 2.2 and 4.1, including without limitation: (i) documentation provided to Generator by PJM after the conclusion of each Base Residual Auction showing the amount of Unforced Capacity offered from the Capacity Facility and cleared by PJM in such Base Residual Auction; (ii) documentation provided to Generator by PJM in advance of each Delivery Year showing the all EFORD measurements for the Capacity Facility for the Delivery Year; (iii) the result of any capability test of the Capacity Facility conducted by PJM; (iv) documentation provided to Generator by PJM in advance of each Delivery Year showing the Available Capacity Amount for the Delivery Year or required to calculate the Available Capacity Amount for the Delivery Year; and (v) documentation notifying Generator of any correction to an input to a calculation, as provided in Section 2.9; provided that Generator may redact from any such documentation data that do not relate to the Capacity Facility;

(g) Provide on a timely basis all documentation reasonably requested by Utility to demonstrate Generator’s compliance with all of its obligations as set forth in this Section 2.3 and affirmative covenants as set forth in Section 6. Utility shall have the right, upon reasonable notice to Generator, to request such information once each year and, in addition, upon the occurrence of any event or upon Utility’s receipt of information that gives Utility reasonable grounds for concern in good faith as to Generator’s compliance with one or more such obligations;

(h) Prepare and file an annual certification to the Board within thirty (30) calendar days after the end of each Delivery Year describing the Generator’s compliance with Section 2.3.3 (b) through Section 2.3.3 (e) and any material actions taken by the Generator under this Agreement.

2.3.4. Cause to be provided to the Utility throughout the Construction Period, Construction Period Security in an amount to be calculated annually equal to the product of $10,000/MW and the Awarded Capacity Amount and the Utility’s Load Ratio, but in no case more than the product of $1 million, and the Utility’s Load Ratio. Such Construction Period Security shall be in the form of a Letter of Credit or Cash held in escrow by the Utility, which shall have the right to draw upon the Construction Period Security as provided in Section 9.4. In
the event of the application of any such Construction Period Security toward any amount owed hereunder to Generator the Generator shall have no obligation to increase the amount of the Construction Period Security beyond the initial amount provided.

2.3.5. Cause to be provided to the Utility throughout the Delivery Term, Delivery Term Security in an amount to be calculated annually equal to the product of $25,000/MW and the Awarded Capacity Amount and the Utility’s Load Ratio with the amount of Delivery Term Security declining pro rata at the conclusion of each Delivery Year over any remaining term of this Agreement. Such Delivery Period Security shall be in the form of a Letter of Credit or Cash held in escrow by the Utility, which shall have the right to draw upon the Delivery Term Security as provided in Section 9.4. In the event of the application of any such Delivery Term Security toward any amount owed hereunder to Generator the Generator shall have no obligation to increase the amount of the Delivery Term Security beyond the initial amount provided.

2.3.6. Fulfill all Generator’s obligations under, and otherwise comply with all terms of, the Construction Period Security and Delivery Term Security.

2.4. Obligations of the Utility. The Utility shall prepare and file an annual report to the Board within thirty (30) calendar days after the end of each Delivery Year describing (i) the status of this Agreement, (ii) the amount of Unforced Capacity and cost of associated Transactions made under this Agreement, (iii) the performance of the Generator in supplying Unforced Capacity and Associated Energy and Associated Ancillary Services under this Agreement, and (iv) any material actions taken by the Generator or the Utility under this Agreement. Nothing in this Agreement imposes upon Utility the obligation to monitor, enforce, or declare an Event of Default with respect to the price of Unforced Capacity, or the price or amount of Associated Energy or Associated Ancillary Services, which Generator offers in or supplies to any PJM Market.

2.5. Conditions Precedent to Obligations. Each obligation of each party under this Agreement is subject to (i) the condition precedent that no Event of Default with respect to the other party has occurred and is continuing, (ii) the condition precedent that no Early Termination Date has occurred or been effectively designated, and (iii) the Board has found that this Agreement is reasonable and that the Utility will be allowed full rate recovery of all prudent and reasonably incurred costs associated with this Agreement.

2.6. Accounts; Change of Account

2.6.1. Payments are to be made to the following accounts:

Generator:
Pay:
For the Account of:
Account Number:
Fed. ABA Number:

Utility:
Pay:
For the Account of:
Account Number:
Fed. ABA Number:

2.6.2. Either party may change its account for receiving a payment by giving written notice to the other party, which notice will be effective for the next payment date that is at least five Business Days after the effective date of such notice unless such other party gives timely notice of a reasonable objection to such change.

2.6.3. The parties agree that any payments hereunder shall be deemed made in full when confirmation is received from the financial institution holding the account into which payment is made that the payment has been successfully received in immediately available funds. Such confirmation shall be considered by the parties as conclusive evidence of receipt.

2.7. Default Interest; Other Amounts. Prior to the occurrence or effective designation of an Early Termination Date, a party that defaults in the performance of any payment obligation will, to the extent permitted by law and subject to Section 9.3.3, be required to pay interest (before as well as after judgment) on the overdue amount to the other party on demand for the period from (and including) the original due date for payment to (but excluding) the date of actual payment, at the Interest Rate. Such interest will be calculated on the basis of a 360-day year, daily compounding and the actual number of days elapsed. Each payment will be made in U.S. Dollars in freely transferable funds via electronic funds transfer, as set forth in Section 2.2, on the relevant Payment Date (or if that date is not a Business Day, on the next Business Day).

2.8. Calculations. Utility shall make all calculations of payments due under Sections 2.2 and 4.1 in accordance with the terms of this Agreement, in good faith and with commercial reasonableness, and its determinations and calculations will be binding, subject to the resolution of any Calculation Dispute. Inaccuracy in any calculation shall not be an Event of Default. The sole remedy of the parties with respect to any inaccuracy of a calculation will be the right (but not the obligation), to commence a Calculation Dispute.

2.9. Corrections to Input to Transaction Payment. If PJM revises to correct any of the inputs required for Utility to calculate any payment required under Section 4.1 within the time permitted by PJM’s applicable tariff rate or rate schedule for the revision of PJM charges, Utility will reflect the amount (if any) that is payable as a result of that correction (including without limitation interest on such amount payable from the date of original payment under Section 4.1 through the date of payment under this Section 2.9 at the Interest Rate) in the calculation of payment of payments due for the Delivery Year after Utility receives notice of the revision. Utility shall calculate the correction so as to place the parties in the same economic position after such payment as they would have been had the correct input been employed initially.

2.10. Substitution Return and Handling of Credit Support

2.10.1. Election to Change Form of Credit Support. With respect to the Construction Period Security or the Delivery Term Security, the Generator may, at any time and
from time to time, replace (i) a Letter of Credit with Cash held under a Cash Escrow Agreement, (ii) Cash held under a Cash Escrow Agreement with a Letter of Credit, or (iii) a Letter of Credit with a different Letter of Credit, provided that any such substitute Cash and Cash Escrow Agreement or substitute Letter of Credit (as the case may be) meets the requirements for Construction Period Security or Delivery Term Security, as applicable, whereupon the Utility shall cooperate with the Generator in obtaining the concurrent release, termination or return of the Letter of Credit or Cash and Cash Escrow Agreement (as the case may be) being replaced.

2.10.2. **Return of Original Credit Support Documents.** Without limitation to the generality of the foregoing, the Utility shall return to the Generator all original Credit Support Documents, and all amendment, extension and other documents related thereto, within twenty (20) calendar days of the termination, cancellation or replacement thereof.

2.10.3. **Handling of Cash Collateral.** If any collateral in the form of Cash is expected to be or is received by the Utility pursuant to this Agreement, whether following a Letter of Credit drawing due to failure on the part of the issuer of the Letter of Credit to renew or extend the Letter of Credit or otherwise, the parties shall cooperate to cause such collateral in the form of Cash to be delivered as soon as practicable to a custodian to be held pursuant to a Cash Escrow Agreement. Any collateral in the form of Cash that is received and held by the Utility pending delivery to a custodian shall be segregated by the Utility from its other property and held exclusively in accounts with Qualified Banks.

**SECTION 3**

**TERM AND TERMINATION**

This Agreement is effective as of the Effective Date and will remain in effect until the later to occur of the Termination Date or the fulfillment by the parties of all obligations hereunder.

**SECTION 4**

**TRANSACTIONS**

4.1. **Transactions.**

4.1.1. If, for a Delivery Year, the SOCP is greater than the RCP then, subject to Section 2.5, Utility will pay Generator each Month during the Delivery Year one-twelveth of the product of (i) the difference between the SOCP and the RCP, (ii) the Available Capacity Amount, (iii) the number of days in the Delivery Year; and (iv) Utility Load Ratio, each for the applicable Delivery Year.

4.1.2. If, for a Delivery Year, the RCP is greater than the SOCP then, subject to Section 2.5, Generator will pay Utility each Month an amount equal to one-twelveth of the product of (i) the difference between the RCP and the SOCP, (ii) the Available Capacity Amount, (iii) the number of days in the Delivery Year; and (iv) Utility Load Ratio, each for the applicable Delivery Year.
Amount, (iii) the number of days in the Delivery Year, and (iv) Utility Load Ratio, each for the applicable Delivery Year.

4.2. **Structure of Transaction.** Nothing in this Agreement shall entitle or obligate Utility to purchase, or take title to or delivery of, capacity, electric energy, or ancillary services from the Capacity Facility.

**SECTION 5**

**REPRESENTATIONS AND WARRANTIES**

5.1. **Mutual Representations and Warranties.** Each party represents to the other party, from the Effective Date, and, except as specified below, continuing throughout the Delivery Term, that:

5.1.1. It is duly organized and validly existing under the laws of the jurisdiction of its organization or incorporation and, if relevant under such laws, in good standing.

5.1.2. It has the power (i) to execute this Agreement, the Construction Period Security, Delivery Term Security and any other documentation relating hereto or thereto, (ii) to deliver this Agreement and cause to be delivered the Construction Period Security, Delivery Term Security and any other documentation that it is required by this Agreement to deliver and (iii) to perform its obligations hereunder or thereunder and has taken all necessary action to authorize such execution, delivery and performance.

5.1.3. As of the Effective Date, such execution, delivery and performance do not violate or conflict with any law applicable to it, any order or judgment of any court or other agency of government applicable to it or any of its assets or any contractual restriction binding on or affecting it or any of its assets.

5.1.4. Its obligations under this Agreement, the Construction Period Security, and Delivery Term Security constitute its legal, valid and binding obligations, enforceable in accordance with their respective terms (subject to applicable bankruptcy, reorganization, insolvency, moratorium or similar laws affecting creditors’ rights generally and subject, as to enforceability, to equitable principles of general application (regardless of whether enforcement is sought in a proceeding in equity or at law)).

5.1.5. As of the Effective Date, all governmental and other consents that are required to have been obtained by it with respect to this Agreement, the Construction Period Security, and the Delivery Term Security are in full force and effect and all conditions of any such consents have been complied with.

5.1.6. As of the Effective Date, no Event of Default or event which, with notice or the passage of time or both, would constitute an Event of Default has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or
performing its obligations hereunder or under the Construction Period Security or Delivery Term Security.

5.1.7. All applicable information that is furnished in writing by or on behalf of it to the other party required by Section 6.1 is, as of the date of the information, true, accurate and complete in every material respect.

5.1.8. It is an “eligible contract participant” within the meaning of Section 1(a)18 of the Commodities Exchange Act, as amended.

5.1.9. In connection with the negotiation of, the entering into, and the confirming of the execution of, this Agreement: (i) it is acting as principal (and not as agent or in any other capacity, fiduciary or otherwise); (ii) the other party is not acting as a fiduciary or financial or investment advisor for it; (iii) it is not relying upon any representations (whether written or oral) of the other party other than the representations expressly set forth in this Agreement; (iv) the other party has not given to it (directly or indirectly through any other Person) any advice, counsel, assurance, guarantee, or representation whatsoever as to the expected or projected success, profitability, return, performance, result, effect, consequence, or benefit (either legal, regulatory, tax, financial, accounting, or otherwise) hereof; (v) it has consulted with its own legal, regulatory, tax, business, investment, financial, and accounting advisors to the extent it has deemed necessary, and it has made its own decision to enter into the Transaction based upon its own judgment and upon any advice from such advisors as it has deemed necessary, and not upon any view expressed by the other party; and (vii) it is entering into this Agreement with a full understanding of all the risks hereof and thereof (economic and otherwise), and it is capable of assuming and willing to assume (financially and otherwise) those risks.

5.1.10. It is a “United States person” (within the meaning of section 7701(a)(30) of the Internal Revenue Code of 1986, as amended, and is exempt from backup withholding under Internal Revenue Code section 3406 and relevant U.S. Department of the Treasury regulations.

5.2. Generator’s Representations and Warranties. Generator hereby represents and warrants to Utility as of the Effective Date that:

5.2.1. Generator’s selection to participate in the LCAPP has been approved by the Board.

5.2.2. Generator is approved by the Board pursuant to the Act as eligible to enter into standard offer capacity agreements with the Electric Public Utilities for the Awarded Capacity Amount at the SOCP.

5.2.3. Generator will not, either alone or in combination with any Affiliate of Generator that is eligible to participate in the LCAPP, enter into financially-settled standard offer capacity agreements for more than 700 MW of Unforced Capacity pursuant to the LCAPP.
SECTION 6
AFFIRMATIVE COVENANTS

Each party agrees with the other that, so long as either party has or may have any obligation hereunder:

6.1. Furnish Specified Information.

6.1.1. Each party will deliver to the other party such proof of the names, true signatures and authority of Persons signing this Agreement on its behalf as the other party may reasonably request upon execution hereof;

6.1.2. Generator will deliver to Utility on a timely basis:

(a) All information required by the Utility to perform the calculations specified in Sections 2.2 and 4.1, including without limitation information supplied to Generator by PJM;

(b) All documents, including all written notifications and other communications from PJM, related to Generator’s compliance or non-compliance with the RPM Rules;

(c) All additional documents required for Utility to provide an annual report to the Board as specified in Section 2.4.

6.2. Maintain Authorizations. Each party will use all reasonable efforts, including the maintenance of records and provision of notices, to maintain in full force and effect all consents, licenses or approvals of PJM and of any Governmental Authority or other authority that are required to be obtained by it with respect to this Agreement, the Construction Period Security, and the Delivery Term Security and its obligations hereunder and thereunder and will use all reasonable efforts to obtain any that may become necessary in the future.

6.3. Comply with Laws and RPM Rules. Each party will comply in all material respects with all Applicable Laws and orders and all RPM Rules to which it may be subject if failure so to comply would materially impair its ability to perform its obligations hereunder or under the Construction Period Security or Delivery Term Security.

6.4. Reporting Requirements. Generator shall be responsible for any recordkeeping, reporting and other requirements applicable to this Agreement under the Commodity Exchange Act, as amended, and the regulations of the Commodity Futures Trading Commission.
SECTION 7
EVENTS OF DEFAULT

7.1. Events of Default. The occurrence at any time with respect to a party of any of the following events constitutes an event of default (an “Event of Default”) with respect to such party:

7.1.1. Failure to Pay. Failure by the party to make, when due, any payment under this Agreement required to be made by it if such failure is not remedied on or before the third (3rd) Business Day after notice of such failure is given to the party.

7.1.2. Failure to Provide Information. Failure by Generator to provide to Utility such information or documentation required by Section 2.3.3 or Section 6.1.2 if such failure is not remedied on or before the fifth (5th) Business Day after notice of such failure is given to Generator by Utility.

7.1.3. Breach of Agreement. Failure by the party to comply with or perform any agreement or obligation (other than an obligation to make any payment under this Agreement or to provide information or documentation) to be complied with or performed by the party in accordance with this Agreement if such failure is not remedied on or before the thirtieth (30th) calendar day after notice of such failure is given to the party, or, in the case of a failure to comply with any applicable provision of the RPM Rules, within the time (if any) provided in the RPM Rules to remedy such failure.

7.1.4. Misrepresentation. A representation made or repeated by the party in this Agreement proves to have been incorrect or misleading in any material respect when made or repeated or deemed to have been made or repeated, and such misrepresentation is not cured within thirty (30) calendar days after such misrepresentation is made or repeated;

7.1.5. Bankruptcy. The party: (i) is dissolved (other than pursuant to a consolidation, amalgamation or merger); (ii) becomes insolvent or is unable to pay its debts or fails or admits in writing its inability generally to pay its debts as they become due; (iii) makes a general assignment, arrangement or composition with or for the benefit of its creditors; (iv) institutes or has instituted against it a proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditors’ rights, or a petition is presented for its winding-up or liquidation, and, in the case of any such proceeding or petition instituted or presented against it, such proceeding or petition (A) results in a judgment of insolvency or bankruptcy or the entry of an order for relief or the making of an order for its winding-up or liquidation or (B) is not dismissed, discharged, stayed or restrained in each case within fifteen (15) calendar days of the institution or presentation thereof; (v) has a resolution passed for its winding-up, official management or liquidation (other than pursuant to a consolidation, amalgamation or merger); (vi) seeks or becomes subject to the appointment of an administrator, provisional liquidator, conservator, receiver, trustee, custodian or other similar official for it or for all or substantially all its assets; (vii) causes or is subject to any event with respect to it which, under the Applicable Laws of any jurisdiction, has an analogous effect to any of the events specified in clauses (i) to (vi)
(inclusive); or (viii) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts; or

7.1.6. **Merger Without Assumption.** The party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer the resulting, surviving or transferee entity fails to assume all the obligations of such party hereunder or under the Construction Period Security or Delivery Term Security.

7.1.7. **Failure to Achieve the Commencement Date.** Generator fails to cause the Capacity Facility to achieve the Commencement Date by no later than two (2) years after the Awarded Commencement Date, except if an event of Force Majeure causes additional delays.

7.1.8. **Failure to Participate in a PJM Market.** Generator fails to submit a supply offer, consistent with Section 2.3.3 for its Unforced Capacity and the Associated Energy and Associated Ancillary Services from the Capacity Facility. Any Capacity Facility shall be required to bid no less than the Awarded Capacity Amount beginning with the Base Residual Auction associated with the Awarded Commencement Date and continuing through the Delivery Term, except if an event of Force Majeure delays the Commencement Date.

7.1.9. **Security Default.** With respect to Generator: (i) failure by Generator to comply with any provision of, or to perform any of its obligations under, either the Construction Period Security or the Delivery Term Security if such failure is continuing after any applicable grace period has elapsed; (ii) the expiration of, termination of, or failure to replace in accordance with Section 2.10 within five (5) Business Days after Utility has delivered notice to Generator of such failure, as appropriate, either the Construction Period Security or the Delivery Term Security prior to its intended expiration date; (iii) the failing or ceasing of either the Construction Period Security or the Delivery Term Security to be in full force and effect for its intended term; (iv) Generator disaffirms, disclaims, repudiates or rejects, in whole or in part, or challenges the validity of, the Construction Period Security or the Delivery Term Security; or (v) a default or event of default, howsoever characterized, occurs under the Construction Period Security or the Delivery Term Security.

**SECTION 8**

**TERMINATION EVENTS**

8.1. **Termination Events.** The occurrence at any time of any of the following events constitutes a Termination Event (a “Termination Event”).

8.1.1. **Illegality.** Due to the adoption of, or any change in, any Applicable Law after the Effective Date, or due to the promulgation of, or any change in, the interpretation by any court, tribunal or regulatory authority with competent jurisdiction of any Applicable Law after such date, it becomes unlawful (other than as a result of a breach by the party of Section 6.2) for a party:
(1) to perform any absolute or contingent obligation to make a payment or to receive a payment in respect of the Transaction or to comply with any other material provision of this Agreement;

(2) to perform any contingent or other obligation which the party has or any other material provision of this Agreement; or

(3) to provide or perform its obligations under the Construction Period Security or the Delivery Period Security.

8.1.2. Invalidity of the Act. If a court invalidates or declares unconstitutional the Act or portion thereof requiring or specifying some performance, right, or obligation of Utility or Generator.

SECTION 9
REMEDIES

9.1. Right to Terminate Following Event of Default or Termination Event.

9.1.1. If at any time an Event of Default with respect to a party (the “Defaulting Party”) has occurred and is then continuing, then the other party (the “Non-Defaulting Party”) may, by not more than twenty (20) calendar days notice in writing to the Defaulting Party specifying the relevant Event of Default, designate a day not earlier than five (5) Business Days after such notice is effective as an Early Termination Date.

9.1.2. If at any time a Termination Event has occurred and is then continuing, then either party in the case of an Illegality or an Invalidity of the Act, may, by not more than twenty (20) calendar days notice in writing to the other party specifying the relevant Termination Event, designate a day not earlier than five (5) Business days after such notice is effective as an Early Termination Date.

9.2. Effect of Designation.

9.2.1. If notice designating an Early Termination Date is given, the Defaulting Party shall have five (5) Business Days to cure any Event of Default. If after such five (5) Business Days the Event of Default or Termination Event is continuing, then the Early Termination Date will occur on the date so designated, whether or not the relevant Event of Default or Termination Event is then continuing.

9.2.2. Upon the occurrence or effective designation of an Early Termination Date, no further payments under Section 2.1 or 2.7 will be required to be made, and this Agreement shall be null and avoid, except with respect to the provisions hereof required to effect payments of the amounts, if any, payable in respect of an Early Termination Date, which amounts shall be determined and paid pursuant to Section 9.3.
9.3. **Payments on Early Termination.** If an Early Termination Date occurs, the following provisions will apply.

9.3.1. **Events of Default.** If the Early Termination Date results from an Event of Default, the Defaulting Party will pay the Non-Defaulting Party: (i) all Unpaid Amounts owing to the Non-Defaulting Party; (ii) all expenses payable under Section 9.5; and (iii), in the case of an Event of Default relating to participating in a Base Residual Auction, an amount equal to the product of (a) the amount, if any, by which the RCP for such Base Residual Auction exceeds the SOCP, (b) the Awarded Capacity Amount; (c) three hundred and sixty-five (365); (d) the Utility Load Ratio, and (e) the number of Delivery Years remaining in the Delivery Term starting with and including the Delivery Year associated with such Base Residual Auction.

9.3.2. **Termination Events.** If an Early Termination Date results from Section 8.1.1 (an Illegality) or Section 8.1.2 (an Invalidity of the Act), each party shall pay to the other all Unpaid Amounts owing pursuant to the terms of this Agreement.

9.3.3. **Notice and Payment.** The party designating an Early Termination Date shall provide notice of such Early Termination Date to the other party. Upon Utility’s issuance or receipt of such notice, Utility shall, as soon as practicable, calculate the amounts payable under Section 9.3.1 or 9.3.2, as applicable, and shall provide the calculation to the parties, specifying the party who is obligated to pay and the amount of such payment. An amount calculated as being due in respect of an Unpaid Amount will be payable, as applicable: (i) on the day that notice of the amount payable is effective (in the case of an Early Termination Date which is designated or occurs as a result of an Event of Default); or (ii) on the day which is two (2) Business Days after the date on which notice of the amount payable is effective (in the case of an Early Termination Date which is designated as a result of a Termination Event). Such amount will be paid together with (to the extent permitted under Applicable Law) interest thereon (before as well as after judgment), from (and including) the relevant Early Termination Date to (but excluding) the date such amount is paid, at the Interest Rate. Such interest will be calculated on the basis of daily compounding and the actual number of days elapsed.

9.4. **Rights Under Construction Period Security and Delivery Term Security**

9.4.1. **Parties’ Rights and Remedies.** If at any time an Early Termination Date has occurred as the result of an Event of Default or a Termination Event with respect to the Generator, then, unless the Generator has paid in full all of its obligations under this Agreement that are then due, the Utility may exercise one or more of the following rights and remedies:

(a) All rights and remedies available to the Utility under the terms of the applicable Letter of Credit or Cash Escrow Agreement, including without limitation the right to draw on such Letter of Credit and Cash held under such Cash Escrow Agreement;

(b) All other rights and remedies available to the Utility under applicable law as the beneficiary in the case of a letter of credit or secured party in the case of Cash held in escrow; and
(c) The right to set-off any amounts payable by the Generator with respect to any obligations under this Agreement against any Cash held on behalf of the Utility under any Cash Escrow Agreement.

9.4.2. Deficiencies and Excess Proceeds. The Utility will return to the Generator any Letter of Credit or Cash held on behalf of the Utility under a Cash Escrow Agreement remaining after liquidation, set-off and/or application under Section 9.4.1 after satisfaction in full of all amounts payable by the Generator with respect to any of its obligations under the Agreement. The Generator in all events will remain liable for any amounts remaining unpaid after any liquidation, set-off and/or application under such Section 9.4.1.

9.5. Expenses. A Defaulting Party will, on demand, indemnify and hold harmless the other party for and against all reasonable out-of-pocket expenses, including legal fees, incurred by the Non-Defaulting Party by reason of the enforcement and protection of its rights hereunder or under the Construction Period Security, the Delivery Term Security, or by reason of the early termination of the Transaction, including, but not limited to, costs of collection.

9.6. LIMITATION OF LIABILITY. NO PARTY WILL BE REQUIRED TO PAY OR BE LIABLE FOR INCIDENTAL, CONSEQUENTIAL, INDIRECT, OR PUNITIVE DAMAGES (WHETHER OR NOT ARISING FROM ITS NEGLIGENCE) TO ANY OTHER PARTY EXCEPT TO THE EXTENT THAT THE PAYMENTS REQUIRED TO BE MADE PURSUANT HERETO ARE DEEMED TO BE SUCH DAMAGES. IF AND TO THE EXTENT ANY PAYMENT REQUIRED TO BE MADE PURSUANT HERETO IS DEEMED TO CONSTITUTE LIQUIDATED DAMAGES, THE PARTIES ACKNOWLEDGE AND AGREE THAT SUCH DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE AND THAT SUCH PAYMENT IS INTENDED TO BE A REASONABLE APPROXIMATION OF THE AMOUNT OF SUCH DAMAGES AND NOT A PENALTY.

SECTION 10
TRANSFER

10.1. Restriction of Assignments. Except as otherwise provided in this Section 10, neither party may assign this Agreement without (i) the other party’s prior written consent, such consent not to be unreasonably delayed, conditioned or withheld, it being understood that refusal to consent to the assignment of the Agreement to a Person that does not own or control the operation of the Capacity Facility shall not be deemed to be unreasonable, and (ii) the prior approval of the Board. Any assignment in violation of this provision shall be void.

10.2. Generator’s Assignment Without Consent. Notwithstanding the foregoing or anything expressed or implied herein to the contrary, Generator may, without the prior written consent of Utility and with notice to the Board, and subject to the last sentence of this Section 10.2, assign this Agreement (i) to a purchaser of all or substantially all of the assets of Generator; or (ii) in connection with the grant of a security interest to any Facility Lender, provided that such security interest does not interfere with the rights of obligations of any party under the Construction Period Security or Delivery Term Security, (iii) in connection with a merger of
Generator with another Person or any other transaction resulting in a direct or indirect change of control of Generator. The foregoing shall be subject to the provisions that such purchaser, Facility Lender, or the Person surviving such merger, as applicable, (i) agrees in writing to be bound by the terms of this Agreement, including the satisfaction of all obligations through its ownership of or control over the operation of the Capacity Facility, and not from another electric generating facility, (ii) shall not under any circumstances have equity or ownership rights to more than 700 MW of Unforced Capacity from electric generation facilities with standard offer capacity agreements, and (iii) shall provide or maintain Construction Period Security and Delivery Term Security as required under this Agreement. In connection with any assignment of this Agreement by the Generator under this Section, the Generator may transfer, sell, pledge, encumber or collaterally assign its rights under this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, and shall provide notice of such assignment to the Board. Utility agrees to reasonably cooperate with Generator with respect to any such financing and other financial arrangements, including but not limited to entering into with the Facility Lender a customary lender consent agreement, which shall include, but not be limited to, customary terms regarding notice to the Facility Lender of any potential Event of Default hereunder and standstill periods with respect to the exercise of remedies hereunder.

10.3. Utility’s Assignment Without Consent. Notwithstanding the foregoing or anything expressed or implied herein to the contrary, Utility may, without the prior written consent of Generator and with notice to the Board, assign this Agreement (i) to a purchaser of all or substantially all of the assets of Utility; or (iii) in connection with a merger of Utility with another Person or any other transaction resulting in a change of control of Utility; provided that such purchaser, Affiliate or the Person surviving such merger, as applicable, agrees in writing to be bound by the terms of this Agreement.

10.4. Assumption by Assignee; No Release from Liabilities. Any permitted assignee or transferee of a party’s interest in this Agreement shall assume all existing and future obligations of such party to be performed under this Agreement. Whether or not prior written consent to an assignment is required hereunder, the assignor shall give notice to the other party and to the Board promptly after a permitted assignment of this Agreement. Unless otherwise agreed to by the parties and except as set forth in Sections 10.2 and 10.3 above, upon any permitted assignment of this Agreement to an assignee and such assignee’s written assumption of this Agreement, the assigning party shall be released from the performance of its obligations under this Agreement for the period from and after the date of such assignment and assumption; provided, however, that in all other cases, the assigning party shall continue to be bound by this Agreement unless the parties otherwise agree.

SECTION 11
NOTICES

11.1. Effectiveness. Any notice or other communication in respect hereof may be given in any manner set forth below (except that a notice or other communication under Section 7, 8 or
9 will not be effective if given by facsimile transmission or electronic messaging system) to the address or number or in accordance with the electronic messaging system details provided and will be deemed effective as indicated: (i) if in writing and delivered in person or by courier, on the date it is delivered; (ii) if sent by telex, on the date the recipient’s answerback is received; (iii) if sent by facsimile transmission, on the date that transmission is received by a responsible employee of the recipient in legible form (the burden of proving receipt will be on the sender and will not be met by a transmission report generated by the sender’s facsimile machine); (iv) if sent by certified or registered mail (airmail, if overseas) or the equivalent (return receipt requested), on the date that mail is delivered or its delivery is attempted; or (v) if sent by electronic messaging system, on the date that electronic message is received, unless the date of that delivery (or attempted delivery) or that receipt, as applicable, is not a Business Day or that communication is delivered (or attempted) or received, as applicable, after the close of business on a Business Day, in which case that communication will be deemed given and effective on the first following day that is a Business Day.

11.2. **Addresses for Notices.**

11.2.1. **Addresses for notices or communications to Generator:**

Address:

11.2.2. **Address for notices or communications to Utility:**

Address:

11.2.3. **Change of Addresses.** Either party may by notice to the other change the address, telex or facsimile number or electronic messaging system details at which notices or other communications are to be given to it.
SECTION 12

RESOLUTION OF DISPUTES

12.1. Notice of Dispute.

12.1.1. In the event of any dispute, controversy or claim arising out of or relating to this Agreement or the breach, termination or validity thereof should arise between the parties (a “Dispute”), a party may declare a Dispute by delivering to the other party a written notice identifying the disputed issue.

12.1.2. If PJM’s RPM is eliminated, then a Dispute shall be deemed to have occurred and both parties shall attempt to develop a replacement for the RCP as provided under Section 12.2.2 to (i) amend this Agreement and (ii) permit Transactions to continue over the remaining Delivery Term, subject to Board approval.

12.1.3. If PJM’s RPM is modified in a material manner such that it adversely affects the performance, calculation or payment of the Transaction, then a party may declare a Dispute and both parties shall attempt to develop a replacement for the RCP as provided under Section 12.2.2 to (i) amend this Agreement and (ii) permit Transactions to continue over the remaining Delivery Term, subject to Board approval.

12.2. Resolution by the Parties

12.2.1. If the Dispute relates to the accuracy of Utility’s calculation of any payment required to be made under this Agreement (a “Calculation Dispute”), then Generator must provide written notice of the Dispute to Utility within ten (10) Business Days of Generator’s receipt of Utility’s calculation of the payment pursuant to Section 2.2., which notice must state the nature of Generator’s disagreement with Utility’s calculation and include all documentation upon which Generator bases its disagreement. Within ten (10) Business Days of Utility’s receipt of a written notice claiming a Calculation Dispute, Utility shall either: (a) notify Generator that Utility agrees the initial calculation was in error and provide a revised calculation of the payment that is the subject of the Calculation Dispute; or (b) provide Generator with the basis of Utility’s determination that the calculation was correct, including all documentation upon which Utility relies. If Generator does not accept Utility’s revised calculation or Utility’s explanation of the original calculation, then, within ten (10) Business Days, executives of both parties shall meet at a mutually agreeable time and place and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the Dispute.

12.2.2. If the Dispute is not a Calculation Dispute, then upon receipt of a written notice claiming a Dispute, executives of both parties shall meet at a mutually agreeable time and place within ten (10) Business Days after delivery of such notice and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the Dispute. In such meetings and exchanges, a party shall have the right to designate as confidential any information that such party offers. No confidential information exchanged in
such meetings for the purpose of resolving a Dispute may be used by a party in litigation against
the other party.

12.2.3. Any correction to a calculation upon which the parties agree to resolve
the Calculation Dispute, shall be payable within ten (10) Business Days of such resolution plus
interest at the Interest Rate.

12.2.4. If the parties are unable to resolve a Dispute between themselves
pursuant to Section 12.2, then the Dispute will be submitted to the Board for resolution.

12.3. Effect of Dispute

The pendency of a Dispute shall not suspend, either: (a) the obligation of the parties to
perform their obligations under this Agreement, including the obligation to make payments, prior
to a Termination Date; or (b) the effectiveness of a notice of an Event of Default under Section
9.1.1 or a notice designating an Early Termination Date under Section 9.1.2.

SECTION 13
MISCELLANEOUS

13.1. Entire Agreement. This Agreement constitutes the entire agreement and
understanding of the parties with respect to its subject matter and supersedes all oral
communication and prior writings with respect thereto.

13.2. Amendments. No amendment, modification or waiver in respect hereof will be
effective unless (i) in writing (including a writing evidenced by a facsimile transmission) and
executed by each of the parties or confirmed by an exchange of telexes or electronic messages on
an electronic messaging system and (ii) until approved by the Board.

13.3. Remedies Cumulative. Except as provided in this Agreement, the rights, powers,
remedies and privileges provided in this Agreement are cumulative and not exclusive of any
rights, powers, remedies and privileges provided by law.

13.4. Counterparts. This Agreement (and each amendment, modification and waiver in
respect of it) may be executed and delivered in counterparts (including by facsimile
transmission), each of which will be deemed an original.

13.5. Execution of Clearing Requirement. In the event the Transaction is determined to
be subject to any requirement that it be executed or cleared pursuant to the Commodities Futures
Trading Commission or similar exchange or multiparty platform, the parties agree to (i)
cooperate to preserve and enforce the provisions of this Agreement and (ii) consent to any
commercially reasonable margin or other requirements.

13.6. No Waiver of Rights. A failure or delay in exercising any right, power or
privilege in respect hereof will not be presumed to operate as a waiver, and a single or partial
exercise of any right, power or privilege will not be presumed to preclude any subsequent or
further exercise, of that right, power or privilege or the exercise of any other right, power or privilege.

13.7. Relationship of the Parties. The parties acknowledge that the relationship between Utility and Generator is an independent contractual relationship and nothing in this Agreement shall create any joint venture, partnership or principal/agent relationship between Utility and Generator. Neither Utility nor Generator shall have any right, power or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other party in any way.

13.8. Governing Law and Jurisdiction

13.8.1. Governing Law. This Agreement will be governed by and construed in accordance with the substantive law of the State of New Jersey, without regard to the application of such state’s laws relating to conflicts of laws.

13.8.2. Jurisdiction. With respect to any suit, action or proceedings relating hereto (“Proceedings”), each party irrevocably: (i) submits to the exclusive jurisdiction of the courts of the State of New Jersey; and (ii) waives any objection which it may have at any time to the laying of venue of any Proceedings brought in any such court, waives any claim that such Proceedings have been brought in an inconvenient forum and further waives the right to object, with respect to such Proceedings, that such court does not have any jurisdiction over such party. Nothing in this Agreement precludes either party from bringing Proceedings in any other jurisdiction in order to enforce any judgment obtained in any Proceedings referred to in the preceding sentence.

13.9. Waiver of Immunities. Each party irrevocably waives, to the fullest extent permitted by Applicable Law, with respect to itself and its revenues and assets (irrespective of their use or intended use), all immunity on the grounds of sovereignty or other similar grounds from (i) suit, (ii) jurisdiction of any court, (iii) relief by way of injunction, order for specific performance or for recovery of property, (iv) attachment of its assets (whether before or after judgment) and (v) execution or enforcement of any judgment to which it or its revenues or assets might otherwise be entitled in any Proceedings in the courts of any jurisdiction and irrevocably agrees, to the extent permitted by Applicable Law, that it will not claim any such immunity in any Proceedings.

13.10. Severability. The invalidity or unenforceability of any provision of this Agreement shall not affect the other provisions hereof. If any provision of this Agreement is held to be invalid, the scope of the rights and duties created thereby shall be reduced by the smallest extent necessary to conform such provision to applicable law, preserving to the greatest extent the intent of the parties to create such rights and duties as set out herein. If necessary to preserve the intent of the parties hereto and the prevailing economic balance between the parties at the Effective Date, the parties shall negotiate in good faith to amend this Agreement, adopting a substitute provision that is legally binding and enforceable for the one deemed invalid or unenforceable, provided that such amended Agreement shall be subject to Board approval.
13.11. **Waiver of Jury Trial.** TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED. EACH PARTY ACKNOWLEDGES THAT IT AND THE OTHER PARTY HAVE BEEN INDUCED TO ENTER HEREINTO BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION.

IN WITNESS WHEREOF the parties have executed this Agreement as of the date first above written.

By: __________________________
Name: _________________________
Title: __________________________
Company: _______________________

By: __________________________
Name: _________________________
Title: __________________________
Company: _______________________
DESCRIPTION OF THE CAPACITY FACILITY

General Technology (such as combined cycle, steam cycle, integrated gasification combined cycle, nuclear, wind, etc.): ______________________________

Size (net MW of installed capacity): ______________________________

Full Load Heat Rate (BTU/kWh, HHV, summer rating): ______________________________

Primary Fuel (such as coal, gas, residual oil, distillate oil): ______________________________

Secondary Fuel (if applicable): ______________________________

Number and Configuration of Prime Movers (such as two industrial frame gas turbines plus one steam turbine generator, single pulverized fuel boiler plus steam turbine generator, two circulating fluidized bed boiler plus steam turbine generator, nuclear plant uprate, twenty onshore wind turbines): ______________________________

Location (town or city, county, state): ______________________________

Owner(s) and Ownership Percentage(s): ______________________________

________________________
FORM OF CONSTRUCTION PERIOD SECURITY LETTER OF CREDIT

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

Reference Number: __________________________ Date: _______________________

AMOUNT: USD __________________________

EXPIRY: __________________________

BENEFICIARY: __________________________

APPLICANT: __________________________

[UTILITY]  [GENERATOR]

[ADDRESS OF UTILITY]  [ADDRESS OF GENERATOR]

Ladies and Gentlemen:

[BANK] (“we” or the “Bank”) hereby establish our Irrevocable Nontransferable Standby Letter of Credit No. _________ (this “Letter of Credit”) in your favor in the amount of XXX AND XX/100 Dollars ($ ___ ) (the “Available Amount”), effective immediately and expiring at 5:00 p.m., Eastern Prevailing Time, on the Expiration Date (as hereinafter defined).

This Letter of Credit expires and shall be of no further force or effect upon the close of business on _____________ or, if such day is not a Business Day (as hereinafter defined), on the next [preceding] [succeeding] Business Day (the “Expiration Date”); provided, however, that this Letter of Credit shall automatically be extended for additional one-year terms unless we provide written notice to you, by certified mail return receipt requested or overnight delivery, at least 60 days prior to the then current Expiration Date. For the purposes hereof, “Business Day” shall mean any day on which commercial banks are not authorized or required to close in New York, NY.

Subject to the terms and conditions herein, funds under this Letter of Credit are available to Beneficiary by presentation of your sight draft(s) drawn on the Bank of the following, on or prior to 5:00 p.m. Eastern Prevailing Time, on or prior to the Expiration Date:

1. The original of this Letter of Credit and all amendments (or photocopy of the original for partial drawings); and

2. The Drawing Certificate issued in the form of Exhibit A attached hereto and which forms an integral part hereof, duly completed (including a Statement of Damages, in the
case of a drawing pursuant to paragraph 1.A, 1.B, 1.C or 1.D thereof) and purportedly bearing the signature of an executive officer or director of the Beneficiary.

Notwithstanding the foregoing, any drawing hereunder may be requested by transmitting the requisite documents as described above to the Bank by facsimile at ______________ or such other number as specified from time-to-time by the Bank.

The facsimile transmittal shall be deemed delivered when received, provided, however, that the original documents referenced in paragraphs 1 and 2 above and the sight draft referenced above are received by the Bank prior to 5:00 p.m. Eastern Prevailing Time on the third Business Day following receipt of such facsimile transmittal.

Partial drawing of funds shall be permitted under this Letter of Credit, and this Letter of Credit shall remain in full force and effect with respect to any continuing balance; provided that, the Available Amount shall be reduced by the amount of each such drawing.

This Letter of Credit may be cancelled upon written notice from the Beneficiary, requesting that the Letter of Credit be cancelled, accompanied by the original of this Letter of Credit and all amendments.

This Letter of Credit is not transferable or assignable. Any purported transfer or assignment shall be void and of no force or effect.

Banking charges shall be the sole responsibility of the Applicant.

This Letter of Credit sets forth in full our obligations and such obligations shall not in any way be modified, amended, amplified or limited by reference to any documents, instruments or agreements referred to herein, except only the attachment referred to herein; and any such reference shall not be deemed to incorporate by reference any document, instrument or agreement except for such attachment.

The Bank engages with the Beneficiary that Beneficiary’s drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored if presented to the Bank on or before the Expiration Date.

Except so far as otherwise stated, this Letter of Credit is subject to the International Standby Practices ISP98 (also known as International Chamber of Commerce Publication No. 590), or revision currently in effect (the “ISP”). As to matters not covered by the ISP, the laws of the State of New York, without regard to the principles of conflicts of laws thereunder (other than Section 5-1401 of the General Obligations Law of the State of New York), shall govern all matters with respect to this Letter of Credit.
AUTHORIZED SIGNATURE for Issuer

(Name)

Title:
EXHIBIT A

DRAWING CERTIFICATE

TO [ISSUING BANK NAME]

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

No. _______________

DRAWING CERTIFICATE

Bank

Bank Address

Subject: Irrevocable Nontransferable Standby Letter of Credit

Reference Number: _______________

The undersigned executive officer or director of [UTILITY] (the “Beneficiary”), hereby certifies under penalty of perjury to [ISSUING BANK NAME] (the “Bank”), and [GENERATOR] (the “Applicant”), with reference to Irrevocable Nontransferable Standby Letter of Credit No. _______________, dated _______________ (the Letter of Credit”), issued by the Bank in favor of the Beneficiary, as follows as of the date hereof:

1. The Beneficiary is entitled to payment of an amount equal to $_________ under that certain Standard Offer Capacity Agreement between Applicant and Beneficiary dated as of _______________, 20___ (the “Agreement”) for the following reason(s) [check applicable provision]:

   [ ]A. An “Early Termination Date” (as defined in the Agreement) has occurred or been designated as a result of an “Event of Default” (as defined in the Agreement) or Termination Event for which the Applicant owes a termination payment, and the true calculation of such payment amount is set forth in detail in the attached Statement of Damages.

   [ ]B. (i) (A) The Bank has heretofore provided written notice to the Beneficiary of the Bank’s intent not to renew the Letter of Credit following the present Expiration Date thereof or (B) the Letter of Credit will expire in fewer than 30 days from the date hereof, and (ii) the Applicant is required to but has not provided Beneficiary alternative Construction Period Security (as defined in the Agreement). The Applicant will hold the proceeds of the Letter of
Credit as cash collateral for any and all amounts owing to the Applicant under the Agreement until such time as it is entitled to payment of such amount pursuant to the Agreement.

2. Based upon the foregoing, the Beneficiary hereby makes demand under the Letter of Credit for payment of _____________________________ U.S. DOLLARS AND ___/100ths (U.S.$_________), which amount does not exceed (i) the amount set forth in paragraph 1 above and (ii) the Available Amount under the Letter of Credit as of the date hereof.

3. Funds paid pursuant to the provisions of the Letter of Credit shall be wire transferred to the Beneficiary in accordance with the following instructions:

___________________________________

___________________________________

___________________________________

Unless otherwise provided herein, capitalized terms which are used and not defined herein shall have the meaning given each such term in the Letter of Credit.

IN WITNESS WHEREOF, this Certificate has been duly executed and delivered, [together with the attached Statement of Damages,] on behalf of the Beneficiary by its undersigned executive officer or director as of this ____ day of ___________ , _____.

Beneficiary: __ [UTILITY]

By: ________________________________
Name: ______________________________
Title: ______________________________

Copy to:

[GENERATOR]

[ADDRESS OF GENERATOR]

[ATTACH STATEMENT OF DAMAGES, IF APPLICABLE]
STATEMENT OF DAMAGES

For the reason(s) indicated in the Drawing Certificate to which this Statement of Damages is attached, and which this Statement of Damages is an integral part of, the Beneficiary certifies (i) that it has calculated that $   (or a greater amount) is presently due and owing to Beneficiary on account of [a continuing “Event of Default”] [a Termination Event] [an “Early Termination Date”] (as defined in the Agreement), calculated as set forth in detail below, and (ii) such calculation is made in accordance with Sections 2.3.4 and 9 of the Agreement.

[INSERT DETAILED CALCULATION OF DAMAGES]
ATTACHMENT C

FORM OF CASH ESCROW AGREEMENT FOR CONSTRUCTION PERIOD SECURITY

Pursuant to this Escrow Agreement ("Agreement") dated [__________], [UTILITY] (the "Secured Party") and [GENERATOR] (the "Depositor") hereby establish an Escrow Account (the "Account") with ____________ (the "Agent") (the Secured Party, Depositor and Agent hereafter referred to individually as a "Party" and collectively as the "Parties"), to be maintained and administered for the purposes described in Schedule I attached hereto in accordance with the following terms and conditions:

The funds and/or property described on Schedule I attached hereto and incorporated herein (the "Cash Deposit") will be deposited in the Account upon delivery thereof to the Agent in the manner and at the time(s) specified in the said Schedule I. The Agent is hereby authorized and directed by the Secured Party and the Depositor, as their escrow agent, to hold, deal with and dispose of the Cash Deposit as provided in the Instructions set forth in Schedule II attached hereto and incorporated herein; subject to and in accordance with, however, the terms and conditions set forth in the following paragraphs of this Agreement, which in all events shall govern and control over any contrary or inconsistent provisions contained in Schedules I or II attached hereto.

Terms not defined but used herein and in Schedules I, II, III and IV hereto will have the meanings given to them in the Standard Offer Capacity Agreement (the "SOCA"), dated as of [__________], 20__ between Secured Party and Depositor.

1. Agent’s Duties. Agent’s duties and responsibilities shall be limited to those expressly set forth in this Agreement, and Agent shall not be subject to, or obliged to recognize, any other agreement between any or all of the other Parties or any other persons, even though reference thereto may be made herein; provided, however, this Agreement may be amended at any time or times by an instrument in writing signed by all of the Parties. Agent shall not be subject to or obligated to recognize any notice, direction or instruction of any or all of the Parties or of any other person, except as expressly provided for and authorized in Schedule II, and in performing any duties under this Agreement, the Agent shall not be liable to any Party for consequential damages (including, without limitation lost profits), losses or expenses, except and to the extent attributable to any gross negligence or willful misconduct on the part of the Agent.

2. Court Orders or Process. If any controversy arises between the Parties, or with any other party, concerning the subject matter of this Agreement, its terms or conditions, Agent will not be required to determine and/or resolve the controversy or to take any action regarding it. Agent may hold all documents and funds and may wait for settlement of any such controversy by final appropriate legal proceedings or other means as, in Agent’s discretion, Agent may require as evidence of final settlement, despite what may be set forth elsewhere in this Agreement. In such event, Agent will not be liable for interest or damage. Agent is authorized, in its sole discretion, to comply with orders issued or process entered by any court with respect to the Account, the Cash Deposit or this Agreement, without determination by the Agent of such court’s jurisdiction in the matter. If any part of the Cash Deposit are at any time attached,
garnished, or levied upon under any court order, or in case the payment, assignment, transfer, conveyance or delivery of any such property shall be stayed or enjoined by any court order, or in case any order, judgment or decree shall be made or entered by any court affecting such property or any part thereof, then in any such event, Agent is authorized, in its sole discretion, to rely upon and comply with any such order, writ, judgment or decree which it is advised by legal counsel of its own choosing is binding upon it; and if Agent complies with any such order writ, judgment or decree, it shall not be liable to either the Secured Party or the Depositor or to any other person, firm or corporation by reason of such compliance, even though such order, writ, judgment or decree may be subsequently reversed, modified, annulled, set aside or vacated.

3. Agent’s Actions and Reliance. Agent shall not be personally liable for any act taken or omitted by it hereunder if taken or omitted by it in good faith and in the exercise of its own best judgment, except and to the extent any such act or omission constitutes gross negligence or willful misconduct on the part of the Agent. Agent shall also be fully protected in relying upon any written notice, instruction, direction, certificate or document provided to it under and pursuant to this Agreement that in good faith it believes to be genuine, including written instructions from the Secured Party or the Depositor in the form of the attached Exhibit(s), if any.

4. Collections. Unless otherwise specifically indicated in Schedule II, Agent shall proceed as soon as practicable to collect any checks, interest due, matured principal or other collection items with respect to Cash Deposit at any time deposited in the Account. All such collections shall be subject to the usual collection procedures regarding items received by Agent for deposit or collection. Agent shall not be responsible for any collections with respect to the Cash Deposit if Agent is not registered as record owner thereof or otherwise is not entitled to request or receive payment thereof as a matter of legal or contractual right. All collection payments or receipts shall be deposited to the respective Account, except as otherwise provided in Schedule II. Agent shall not be required or have a duty to notify anyone of any payment or maturity under the terms of any instrument, security or obligation deposited in the Account, nor to take any legal action to enforce payment of any check, instrument or other security deposited in the Account. The Account is a safekeeping escrow account, and no interest shall be paid by Agent on any money deposited or held therein, except as provided in Section 6 hereof.

5. Agent Responsibility. Agent shall not be responsible or liable for the sufficiency or accuracy of the form, execution, validity or genuineness of documents, instruments or securities now or hereafter deposited in the Account, or of any endorsement thereon, or for any lack of endorsement thereon, or for any description therein. Registered ownership of or other legal title to Cash Deposit deposited in the Account shall be maintained in the name of Agent, or its nominee, only if expressly provided in Schedule II. Agent may maintain qualifying Cash Deposit in a Federal Reserve Bank or in any registered clearing agency as Agent may select, and may register such deposited Cash Deposit in the name of Agent or its agent or nominee on the records of such Federal Reserve Bank or such registered clearing agency or a nominee of either. Agent shall not be responsible or liable in any respect on account of the identity, authority or rights of the persons executing or delivering or purporting to execute or deliver any such document, security or endorsement or this Agreement.
6. Investments. All monies held in the Account shall be invested by Agent in a triple “A” rated money market fund or in such other investments as may be provided for in Schedule III. The shares of the funds are not deposits or obligations of, or guaranteed by any bank, nor are they insured by the Federal Deposit Insurance Corporation, the Federal Reserve Board or any other agency. The investment in such fund or other investments may involve investment risk, including possible loss of principal. The Agent shall not be liable for losses, penalties or charges incurred upon any sale or purchase of any such investment. All interest, dividends, distributions and other accretions to the Cash Deposit shall [become part of the Cash Deposit] [be disbursed pursuant to Schedule III]. All entities entitled to receive interest or income from the Account will provide Agent with a W-9 or W-8 IRS tax form prior to the disbursement of interest or income. A statement of citizenship will be provided if requested by Agent.

7. Notices/Directions to Agent. Notices and directions to Agent from the Secured Party or the Depositor, or from other persons authorized to give such notices or directions as expressly set forth in Schedule II, shall be in writing and signed by an authorized representative as identified pursuant to Schedule II, and shall not be deemed to be given until actually received by Agent’s employee or officer who administers the Account. Agent shall not be responsible or liable for the authenticity or accuracy of notices or directions properly given hereunder if the written form and execution thereof on its face purports to satisfy the requirements applicable thereto as set forth in Schedule II, as determined by Agent in good faith without additional confirmation or investigation.

8. Books and Records. Agent shall maintain books and records regarding its administration of the Account, and the deposit, investment, collections and disbursement or transfer of Cash Deposit, shall retain copies of all written notices and directions sent or received by it in the performance of its duties hereunder, and shall afford each of the Secured Party and the Depositor reasonable access, during regular business hours, to review and make photocopies (at Depositor’s cost) of the same.

9. Disputes Among Depositors and/or Third Parties. In the event Agent is notified of any dispute, disagreement or legal action between the Secured Party and the Depositor and/or any third parties, relating to or arising in connection with the Account, the Cash Deposit or the performance of the Agent’s duties under this Agreement, the Agent shall be authorized and entitled, subject to Section 2 hereof, to suspend further performance hereunder, to retain and hold the Cash Deposit then in the Account, and to take no further action with respect thereto until the matter has been fully resolved, as evidenced by written notification signed by the Secured Party and the Depositor and any other parties to such dispute, disagreement or legal action.

10. Notice by Agent. Any notices which Agent is required or desires to give hereunder to the Secured Party or the Depositor shall be in writing and may be given by mailing the same to the address indicated below opposite the signature of such Party (or to such other address as said Party may have theretofore substituted therefore by written notification to Agent), by United States certified or registered mail, postage prepaid, by reputable overnight courier service, or by facsimile, so long as receipt of any such facsimile is confirmed. For all purposes hereof, any notice so mailed shall be as effective as though served upon the person of the Party to whom it was mailed on the third (3rd) business day after the time it is deposited in the United
States mail by Agent, properly addressed and with postage prepaid, whether or not such Party thereafter actually receives such notice. Notice given in any other manner shall be effective upon receipt. Whenever under the terms hereof the time for Agent’s giving a notice or performing an act falls upon a Saturday, Sunday, or holiday, such time shall be extended to the next business day.

11. Agent Compensation and Expenses. Agent shall be paid a fee for its services as set forth on Schedule IV attached hereto and incorporated herein, which shall be subject to increase upon notice sent to the Secured Party and the Depositor, and reimbursed for its reasonable costs and expenses incurred. The Depositor will pay all Agent’s usual charges and Agent may deduct such sums from the funds deposited. If Agent’s fees, reasonable costs or expenses provided for herein are not promptly paid when due, and if there is no cash or insufficient cash in the Account to pay the same, then upon thirty (30) days’ prior written notice to the Secured Party and the Depositor, Agent may sell such portion of the Cash Deposit held in the Account as necessary and reimburse itself therefor from the proceeds of such sale. In the event that the conditions of this Agreement are not promptly fulfilled; or if Agent renders any service not provided for in this Agreement; or if the Secured Party and the Depositor request a substantial modification of its terms; or if any controversy arises, or if Agent is made a party to or intervenes in any litigation pertaining to this escrow or its subject matter or, in the exercise of its business judgment, finds it necessary to consult with counsel regarding the same, then in any such case Agent shall be reasonably compensated for such extraordinary services and reimbursed for all costs, attorney’s fees (including reasonably allocated costs of in-house counsel), and expenses reasonably incurred by Agent in connection with such default, delay, controversy or litigation, and Agent shall have the right to retain all documents and/or other things of value at any time held by Agent in this escrow until such compensation, fees, costs, and expenses are paid. The Depositor promise to pay these sums upon demand. The Depositor and its respective successors and assigns agree to indemnify and hold Agent harmless against any and all losses, claims, damages, liabilities, and expenses, including reasonable costs of investigation, counsel fees (including reasonably allocated costs of in-house counsel) and disbursements that may be imposed on Agent or incurred by Agent in connection with the performance of its duties under this Agreement. Agent shall have a first lien on the Cash Deposit for such compensation and expenses.

12. Agent Resignation. It is understood that Agent reserves the right to resign at any time by giving written notice of its resignation, specifying the effective date thereof, to the Secured Party and the Depositor. Within thirty (30) days after receiving the aforesaid notice, the Secured Party and the Depositor agree to appoint a successor escrow agent to which Agent may transfer the Cash Deposit then held in the Account, less its unpaid fees, costs and expenses. If a successor escrow agent has not been appointed and has not accepted such appointment by the end of such thirty (30) day period, Agent may apply to a court of competent jurisdiction for the appointment of a successor escrow agent, and the costs, expenses and reasonable attorney’s fees which Agent incurs in connection with such a proceeding shall be paid by the Secured Party and the Depositor.

13. Escrow Termination. If this Agreement shall not have previously terminated, then it shall terminate on [___________], as provided in Schedule II, at which time the Cash
Deposit then held in the Account, less Agent’s unpaid fees, costs and expenses shall be
distributed in the following manner:

[____________________________________________________]

14. Governing Law. This Agreement shall be construed, enforced, and administered
in accordance with the laws of the State of [New Jersey].

15. Automatic Succession. Any company into which the Agent may be merged or
with which it may be consolidated, or any company to whom Agent may transfer a substantial
amount of its Escrow business, shall be the Successor to the Agent without the execution or
filing of any paper or any further act on the part of any of the Parties, anything herein to the
contrary notwithstanding.

16. Disclosure: The Parties hereby agree not to use the name of [insert name of
Agent] to imply an association with the transaction other than that of a legal escrow agent.

17. Counterparts: This Agreement may be executed in any number of counterparts,
each of which shall be an original, but all of which, when taken together, shall constitute and be
one and the same instrument. The exchange of copies of this Agreement and of signature pages
by facsimile transmission shall constitute effective execution and delivery of this Agreement as
to the Parties and may be used in lieu of the original Agreement for all purposes. Signatures of
the Parties transmitted by facsimile shall be deemed to be their original signatures for all
purposes.

The undersigned Agent hereby agrees to hold, deal with and dispose of the Cash Deposit
at any time deposited to the Account in accordance with the foregoing Agreement.

[Signature page follows]
IN WITNESS WHEREOF, the undersigned have affixed their signatures and hereby adopt as part of this instrument Schedules I, II, III and IV, which are incorporated by reference.

SECURED PARTY: ____________________________  DEPOSITOR: ____________________________

By: ____________________________  By: ____________________________
Its: ____________________________  Its: ____________________________

(Address) ____________________________  (Address) ____________________________

(City, State and Zip Code) ____________________________  (City, State and Zip Code) ____________________________

(Telephone) ____________________________  (Telephone) ____________________________

(Facsimile Number) ____________________________  (Facsimile Number) ____________________________

Tax I.D. ____________________________  Tax I.D. ____________________________

_____________________________________, as Agent
By: ____________________________
Its: ____________________________

Notices to Agent shall be sent to:

[Name]
[Address]
[City, State, Zip]

With Fax Copy to:

[Name]
[Facsimile Number]
SCHEDULE I
TO CASH ESCROW AGREEMENT

PURPOSE AND MANNER OF DEPOSITS

Credit Support provided by Depositor in the form of Cash under the SOCA, all investments of such Cash, and all proceeds of such investments.

All Credit Support in the form of Cash provided by the Depositor shall be deposited in the Account promptly upon receipt by the Agent.

Instructions for transfer of funds into the Account:

_____________________
_____________________
_____________________
_____________________
_____________________
SCHEDULE II
TO CASH ESCROW AGREEMENT

INSTRUCTIONS OF DEPOSITORS

1. Upon written notice signed by the Secured Party to the Agent that one or more of the following events has occurred, Agent shall withdraw Cash in the amount specified in such notice from the Account (as described on Schedule I) and shall transfer such Cash in accordance with the Secured Party’s instructions.

   (d) An Early Termination Date (as defined in the SOCA) has occurred or been designated as a result of an Event of Default or a Termination Event (as defined in the Agreement) and a specified amount of the Termination Payment (as defined in the SOCA) owed by the Depositor to the Secured Party remains outstanding.

2. Upon written notice signed by both the Secured Party and the Depositor that the Depositor has replaced a specified amount of Cash in the Account with a Letter of Credit (as defined in the SOCA), the Agent shall withdraw such amount of Cash from Depositor’s Subaccount and transfer such Cash in accordance with the Depositor’s instructions.

3. The Agent shall liquidate such Cash Deposit from the Account as may be necessary to meet the withdrawal instructions under paragraphs 1 through 2 of this Schedule II.

7. Authorized persons referred to in Sections 1 and 7 of the Agreement are as specified below, as such names may be amended from time to time by notice to the Agent:

   For Depositor:

   For Secured Party:
SCHEDULE III
TO CASH ESCROW AGREEMENT

PERMITTED INVESTMENTS
SCHEDULE IV
TO CASH ESCROW AGREEMENT

SCHEDULE OF FEES FOR SERVICES
AS ESCROW AGENT
ATTACHMENT D

FORM OF DELIVERY TERM SECURITY LETTER OF CREDIT

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

Reference Number: __________________________ Date: __________________

AMOUNT: USD __________________________

EXPIRY: __________________________

BENEFICIARY: __________________________ APPLICANT: __________________________

[UTILITY] [GENERATOR]

[ADDRESS OF UTILITY] [ADDRESS OF GENERATOR]

Ladies and Gentlemen:

[BANK] (“we” or the “Bank”) hereby establish our Irrevocable Nontransferable Standby Letter of Credit No. _________ (this “Letter of Credit”) in your favor in the amount of XXX AND XX/100 Dollars ($ _________) (the “Available Amount”), effective immediately and expiring at 5:00 p.m., Eastern Prevailing Time, on the Expiration Date (as hereinafter defined).

This Letter of Credit expires and shall be of no further force or effect upon the close of business on _________ or, if such day is not a Business Day (as hereinafter defined), on the next [preceding] [succeeding] Business Day (the “Expiration Date”); provided, however, that this Letter of Credit shall automatically be extended for additional one-year terms unless we provide written notice to you, by certified mail return receipt requested or overnight delivery, at least 60 days prior to the then current Expiration Date. For the purposes hereof, “Business Day” shall mean any day on which commercial banks are not authorized or required to close in New York, NY.

Subject to the terms and conditions herein, funds under this Letter of Credit are available to Beneficiary by presentation of your sight draft(s) drawn on the Bank of the following, on or prior to 5:00 p.m. Eastern Prevailing Time, on or prior to the Expiration Date:

1. The original of this Letter of Credit and all amendments (or photocopy of the original for partial drawings); and

2. The Drawing Certificate issued in the form of Attachment A attached hereto and which forms an integral part hereof, duly completed (including a Statement of Damages, in the
case of a drawing pursuant to paragraph 1.A, 1.B or 1.C thereof) and purportedly bearing the
signature of an executive officer or director of the Beneficiary.

Notwithstanding the foregoing, any drawing hereunder may be requested by transmitting
the requisite documents as described above to the Bank by facsimile at ______________ or such
other number as specified from time-to-time by the Bank.

The facsimile transmittal shall be deemed delivered when received, provided, however,
that the original documents referenced in paragraphs 1 and 2 above and the sight draft referenced
above are received by the Bank prior to 5:00 p.m. Eastern Prevailing Time on the third Business
Day following receipt of such facsimile transmittal.

Partial drawing of funds shall be permitted under this Letter of Credit, and this Letter of
Credit shall remain in full force and effect with respect to any continuing balance; provided that,
the Available Amount shall be reduced by the amount of each such drawing.

This Letter of Credit may be cancelled upon written notice from the Beneficiary,
requesting that the Letter of Credit be cancelled, accompanied by the original of this Letter of
Credit and all amendments.

This Letter of Credit is not transferable or assignable. Any purported transfer or
assignment shall be void and of no force or effect.

Banking charges shall be the sole responsibility of the Applicant.

This Letter of Credit sets forth in full our obligations and such obligations shall not in any
way be modified, amended, amplified or limited by reference to any documents, instruments or
agreements referred to herein, except only the attachment referred to herein; and any such
reference shall not be deemed to incorporate by reference any document, instrument or
agreement except for such attachment.

The Bank engages with the Beneficiary that Beneficiary’s drafts drawn under and in
compliance with the terms of this Letter of Credit will be duly honored if presented to the Bank
on or before the Expiration Date.

Except so far as otherwise stated, this Letter of Credit is subject to the International
Standby Practices ISP98 (also known as International Chamber of Commerce Publication No.
590), or revision currently in effect (the “ISP”). As to matters not covered by the ISP, the laws
of the State of New York, without regard to the principles of conflicts of laws thereunder (other
than Section 5-1401 of the General Obligations Law of the State of New York), shall govern all
matters with respect to this Letter of Credit.
AUTHORIZED SIGNATURE for Issuer

(Name)

Title:
EXHIBIT A

DRAWING CERTIFICATE

TO [ISSUING BANK NAME]

IRREVOCABLE NONTRANSFERABLE STANDBY LETTER OF CREDIT

No. ________________

DRAWING CERTIFICATE

Bank

Bank Address

Subject: Irrevocable Nontransferable Standby Letter of Credit

Reference Number: ________________

The undersigned executive officer or director of [UTILITY] (the “Beneficiary”), hereby certifies under penalty of perjury to [ISSUING BANK NAME] (the “Bank”), and [GENERATOR] (the “Applicant”), with reference to Irrevocable Nontransferable Standby Letter of Credit No. ________________, dated _______________ (the “Letter of Credit”), issued by the Bank in favor of the Beneficiary, as follows as of the date hereof:

1. The Beneficiary is entitled to payment of an amount equal to $_________ under that certain Standard Offer Capacity Agreement between Applicant and Beneficiary dated as of ________________, 20____ (the “Agreement”) for the following reason(s) [check applicable provision]:

[ ]A. The Payment Date under Section 2.2 of the Agreement has occurred with respect to such amount, and such amount is presently due and owing under Section 4.1.2 of the Agreement.

[ ]B. An “Early Termination Date” (as defined in the Agreement) has occurred or been designated as a result of an “Event of Default” (as defined in the Agreement) or Termination Event for which the Applicant owes a termination payment, and the true calculation of such payment amount is set forth in detail in the attached Statement of Damages.

[ ]C. (i) (A) The Bank has heretofore provided written notice to the Beneficiary of the Bank’s intent not to renew the Letter of Credit following the present Expiration Date thereof or
(B) the Letter of Credit will expire in fewer than 30 days from the date hereof, and (ii) the Applicant is required to but has not provided Beneficiary alternative Delivery Term Security (as defined in the Agreement). The Applicant will hold the proceeds of the Letter of Credit as cash collateral for any and all amounts owing to the Applicant under the Agreement until such time as it is entitled to payment of such amount pursuant to the Agreement.

2. Based upon the foregoing, the Beneficiary hereby makes demand under the Letter of Credit for payment of ______________________________ U.S. DOLLARS AND ___/100ths (U.S.$________), which amount does not exceed (i) the amount set forth in paragraph 1 above and (ii) the Available Amount under the Letter of Credit as of the date hereof.

3. Funds paid pursuant to the provisions of the Letter of Credit shall be wire transferred to the Beneficiary in accordance with the following instructions:

_________________________________________________________________
_________________________________________________________________
_________________________________________________________________

Unless otherwise provided herein, capitalized terms which are used and not defined herein shall have the meaning given each such term in the Letter of Credit.

IN WITNESS WHEREOF, this Certificate has been duly executed and delivered, [together with the attached Statement of Damages,] on behalf of the Beneficiary by its undersigned executive officer or director as of this ____ day of __________ , ____.

Beneficiary: __[UTILITY]__

By: ______________________________
Name: ______________________________
Title: ______________________________

Copy to:

[GENERATOR]

[ADDRESS OF GENERATOR]

[ATTACH STATEMENT OF DAMAGES, IF APPLICABLE]
STATEMENT OF DAMAGES

For the reason(s) indicated in the Drawing Certificate to which this Statement of Damages is attached, and which this Statement of Damages is an integral part of, the Beneficiary certifies (i) that it has calculated that $   (or a greater amount) is presently due and owing to Beneficiary on account of [a failure to make a payment under Section 4.1.2 of the Agreement] [an “Early Termination Date”] (as defined in the Agreement), calculated as set forth in detail below, and (ii) such calculation is made in accordance with Sections [2.3.4 and 9 of the Agreement.

[INSERT DETAILED CALCULATION OF DAMAGES]
ATTACHMENT E

FORM OF CASH ESCROW AGREEMENT FOR DELIVERY TERM SECURITY

Pursuant to this Escrow Agreement (“Agreement”) dated [__________], [UTILITY] (the “Secured Party”) and [GENERATOR] (the “Depositor”) hereby establish an Escrow Account (the “Account”) with ____________ (the “Agent”) (the Secured Party, Depositor and Agent hereafter referred to individually as a “Party” and collectively as the “Parties”), to be maintained and administered for the purposes described in Schedule I attached hereto in accordance with the following terms and conditions:

The funds and/or property described on Schedule I attached hereto and incorporated herein (the “Cash Deposit”) will be deposited in the Account upon delivery thereof to the Agent in the manner and at the time(s) specified in the said Schedule I. The Agent is hereby authorized and directed by the Secured Party and the Depositor, as their escrow agent, to hold, deal with and dispose of the Cash Deposit as provided in the Instructions set forth in Schedule II attached hereto and incorporated herein; subject to and in accordance with, however, the terms and conditions set forth in the following paragraphs of this Agreement, which in all events shall govern and control over any contrary or inconsistent provisions contained in Schedules I or II attached hereto.

Terms not defined but used herein and in Schedules I, II, III and IV hereto will have the meanings given to them in the Standard Offer Capacity Agreement (the “SOCA”), dated as of [__________], 20__ between the Secured Party and Depositor.

1. Agent’s Duties. Agent’s duties and responsibilities shall be limited to those expressly set forth in this Agreement, and Agent shall not be subject to, or obliged to recognize, any other agreement between any or all of the other Parties or any other persons, even though reference thereto may be made herein; provided, however, this Agreement may be amended at any time or times by an instrument in writing signed by all of the Parties. Agent shall not be subject to or obligated to recognize any notice, direction or instruction of any or all of the Parties or of any other person, except as expressly provided for and authorized in Schedule II, and in performing any duties under this Agreement, the Agent shall not be liable to any Party for consequential damages (including, without limitation lost profits), losses or expenses, except and to the extent attributable to any gross negligence or willful misconduct on the part of the Agent.

2. Court Orders or Process. If any controversy arises between the Parties, or with any other party, concerning the subject matter of this Agreement, its terms or conditions, Agent will not be required to determine and/or resolve the controversy or to take any action regarding it. Agent may hold all documents and funds and may wait for settlement of any such controversy by final appropriate legal proceedings or other means as, in Agent’s discretion, Agent may require as evidence of final settlement, despite what may be set forth elsewhere in this Agreement. In such event, Agent will not be liable for interest or damage. Agent is authorized, in its sole discretion, to comply with orders issued or process entered by any court with respect to the Account, the Cash Deposit or this Agreement, without determination by the Agent of such
court’s jurisdiction in the matter. If any Cash Deposit are at any time attached, garnished, or levied upon under any court order, or in case the payment, assignment, transfer, conveyance or delivery of any such property shall be stayed or enjoined by any court order, or in case any order, judgment or decree shall be made or entered by any court affecting such property or any part thereof, then in any such event, Agent is authorized, in its sole discretion, to rely upon and comply with any such order, writ, judgment or decree which it is advised by legal counsel of its own choosing is binding upon it; and if Agent complies with any such order writ, judgment or decree, it shall not be liable to either the Secured Party or the Depositor or to any other person, firm or corporation by reason of such compliance, even though such order, writ, judgment or decree may be subsequently reversed, modified, annulled, set aside or vacated.

3. Agent’s Actions and Reliance. Agent shall not be personally liable for any act taken or omitted by it hereunder if taken or omitted by it in good faith and in the exercise of its own best judgment, except and to the extent any such act or omission constitutes gross negligence or willful misconduct on the part of the Agent. Agent shall also be fully protected in relying upon any written notice, instruction, direction, certificate or document provided to it under and pursuant to this Agreement that in good faith it believes to be genuine, including written instructions from the Secured Party or the Depositor in the form of the attached Exhibit(s), if any.

4. Collections. Unless otherwise specifically indicated in Schedule II, Agent shall proceed as soon as practicable to collect any checks, interest due, matured principal or other collection items with respect to Cash Deposit at any time deposited in the Account. All such collections shall be subject to the usual collection procedures regarding items received by Agent for deposit or collection. Agent shall not be responsible for any collections with respect to any of the Cash Deposit if Agent is not registered as record owner thereof or otherwise is not entitled to request or receive payment thereof as a matter of legal or contractual right. All collection payments or receipts shall be deposited to the respective Account, except as otherwise provided in Schedule II. Agent shall not be required or have a duty to notify anyone of any payment or maturity under the terms of any instrument, security or obligation deposited in the Account, nor to take any legal action to enforce payment of any check, instrument or other security deposited in the Account. The Account is a safekeeping escrow account, and no interest shall be paid by Agent on any money deposited or held therein, except as provided in Section 6 hereof.

5. Agent Responsibility. Agent shall not be responsible or liable for the sufficiency or accuracy of the form, execution, validity or genuineness of documents, instruments or securities now or hereafter deposited in the Account, or of any endorsement thereon, or for any lack of endorsement thereon, or for any description therein. Registered ownership of or other legal title to Cash Deposit deposited in the Account shall be maintained in the name of Agent, or its nominee, only if expressly provided in Schedule II. Agent may maintain qualifying Cash Deposit in a Federal Reserve Bank or in any registered clearing agency as Agent may select, and may register such deposited Cash Deposit in the name of Agent or its agent or nominee on the records of such Federal Reserve Bank or such registered clearing agency or a nominee of either. Agent shall not be responsible or liable in any respect on account of the identity, authority or rights of the persons executing or delivering or purporting to execute or deliver any such document, security or endorsement or this Agreement.
6. Investments. All monies held in the Account shall be invested by Agent in a triple “A” rated money market fund or in such other investments as may be provided for in Schedule III. The shares of the funds are not deposits or obligations of, or guaranteed by any bank, nor are they insured by the Federal Deposit Insurance Corporation, the Federal Reserve Board or any other agency. The investment in such fund or other investments may involve investment risk, including possible loss of principal. The Agent shall not be liable for losses, penalties or charges incurred upon any sale or purchase of any such investment. All interest, dividends, distributions and other accretions to the Cash Deposit shall [become part of the Cash Deposit] [be disbursed pursuant to Schedule III]. All entities entitled to receive interest or income from the Account will provide Agent with a W-9 or W-8 IRS tax form prior to the disbursement of interest or income. A statement of citizenship will be provided if requested by Agent.

7. Notices/Directions to Agent. Notices and directions to Agent from the Secured Party or the Depositor, or from other persons authorized to give such notices or directions as expressly set forth in Schedule II, shall be in writing and signed by an authorized representative as identified pursuant to Schedule II, and shall not be deemed to be given until actually received by Agent’s employee or officer who administers the Account. Agent shall not be responsible or liable for the authenticity or accuracy of notices or directions properly given hereunder if the written form and execution thereof on its face purports to satisfy the requirements applicable thereto as set forth in Schedule II, as determined by Agent in good faith without additional confirmation or investigation.

8. Books and Records. Agent shall maintain books and records regarding its administration of the Account, and the deposit, investment, collections and disbursement or transfer of Cash Deposit, shall retain copies of all written notices and directions sent or received by it in the performance of its duties hereunder, and shall afford each of the Secured Party and the Depositor reasonable access, during regular business hours, to review and make photocopies (at Depositor’s cost) of the same.

9. Disputes Among Depositors and/or Third Parties. In the event Agent is notified of any dispute, disagreement or legal action between the Secured Party and the Depositor and/or any third parties, relating to or arising in connection with the Account, the Cash Deposit or the performance of the Agent’s duties under this Agreement, the Agent shall be authorized and entitled, subject to Section 2 hereof, to suspend further performance hereunder, to retain and hold the Cash Deposit then in the Account, and to take no further action with respect thereto until the matter has been fully resolved, as evidenced by written notification signed by the Secured Party and the Depositor and any other parties to such dispute, disagreement or legal action.

10. Notice by Agent. Any notices which Agent is required or desires to give hereunder to the Secured Party or the Depositor shall be in writing and may be given by mailing the same to the address indicated below opposite the signature of such Party (or to such other address as said Party may have theretofore substituted therefor by written notification to Agent), by United States certified or registered mail, postage prepaid, by reputable overnight courier service, or by facsimile, so long as receipt of any such facsimile is confirmed. For all purposes hereof, any notice so mailed shall be as effective as though served upon the person of the Party to whom it was mailed on the third (3rd) business day after the time it is deposited in the United
States mail by Agent, properly addressed and with postage prepaid, whether or not such Party thereafter actually receives such notice. Notice given in any other manner shall be effective upon receipt. Whenever under the terms hereof the time for Agent’s giving a notice or performing an act falls upon a Saturday, Sunday, or holiday, such time shall be extended to the next business day.

11. Agent Compensation and Expenses. Agent shall be paid a fee for its services as set forth on Schedule IV attached hereto and incorporated herein, which shall be subject to increase upon notice sent to the Secured Party and the Depositor, and reimbursed for its reasonable costs and expenses incurred. The Depositor will pay all Agent’s usual charges and Agent may deduct such sums from the funds deposited. If Agent’s fees, reasonable costs or expenses provided for herein are not promptly paid when due, and if there is no cash or insufficient cash in the Account to pay the same, then upon thirty (30) days’ prior written notice to the Secured Party and the Depositor, Agent may sell such portion of the Cash Deposit held in the Account as necessary and reimburse itself therefor from the proceeds of such sale. In the event that the conditions of this Agreement are not promptly fulfilled; or if Agent renders any service not provided for in this Agreement; or if the Secured Party and the Depositor request a substantial modification of its terms; or if any controversy arises, or if Agent is made a party to or intervenes in any litigation pertaining to this escrow or its subject matter or, in the exercise of its business judgment, finds it necessary to consult with counsel regarding the same, then in any such case Agent shall be reasonably compensated for such extraordinary services and reimbursed for all costs, attorney’s fees (including reasonably allocated costs of in-house counsel), and expenses reasonably incurred by Agent in connection with such default, delay, controversy or litigation, and Agent shall have the right to retain all documents and/or other things of value at any time held by Agent in this escrow until such compensation, fees, costs, and expenses are paid. The Depositor promise to pay these sums upon demand. The Depositor and its respective successors and assigns agree to indemnify and hold Agent harmless against any and all losses, claims, damages, liabilities, and expenses, including reasonable costs of investigation, counsel fees (including reasonably allocated costs of in-house counsel) and disbursements that may be imposed on Agent or incurred by Agent in connection with the performance of its duties under this Agreement. Agent shall have a first lien on the Cash Deposit for such compensation and expenses.

12. Agent Resignation. It is understood that Agent reserves the right to resign at any time by giving written notice of its resignation, specifying the effective date thereof, to the Secured Party and the Depositor. Within thirty (30) days after receiving the aforesaid notice, the Secured Party and the Depositor agree to appoint a successor escrow agent to which Agent may transfer the Cash Deposit then held in the Account, less its unpaid fees, costs and expenses. If a successor escrow agent has not been appointed and has not accepted such appointment by the end of such thirty (30) day period, Agent may apply to a court of competent jurisdiction for the appointment of a successor escrow agent, and the costs, expenses and reasonable attorney’s fees which Agent incurs in connection with such a proceeding shall be paid by the Secured Party and the Depositor.

13. Escrow Termination. If this Agreement shall not have previously terminated, then it shall terminate on [___________], as provided in Schedule II, at which time the Cash
Deposit then held in the Account, less Agent’s unpaid fees, costs and expenses shall be distributed in the following manner:

14. Governing Law. This Agreement shall be construed, enforced, and administered in accordance with the laws of the State of [New Jersey].

15. Automatic Succession. Any company into which the Agent may be merged or with which it may be consolidated, or any company to whom Agent may transfer a substantial amount of its Escrow business, shall be the Successor to the Agent without the execution or filing of any paper or any further act on the part of any of the Parties, anything herein to the contrary notwithstanding.

16. Disclosure: The Parties hereby agree not to use the name of [insert name of Agent] to imply an association with the transaction other than that of a legal escrow agent.

17. Counterparts: This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which, when taken together, shall constitute and be one and the same instrument. The exchange of copies of this Agreement and of signature pages by facsimile transmission shall constitute effective execution and delivery of this Agreement as to the Parties and may be used in lieu of the original Agreement for all purposes. Signatures of the Parties transmitted by facsimile shall be deemed to be their original signatures for all purposes.

The undersigned Agent hereby agrees to hold, deal with and dispose of the Cash Deposit at any time deposited to the Account in accordance with the foregoing Agreement.

[Signature page follows]
IN WITNESS WHEREOF, the undersigned have affixed their signatures and hereby adopt as part of this instrument Schedules I, II, III and IV, which are incorporated by reference.

<table>
<thead>
<tr>
<th>SECURED PARTY:</th>
<th>DEPOSITOR:</th>
</tr>
</thead>
<tbody>
<tr>
<td>By:</td>
<td>By:</td>
</tr>
<tr>
<td>Its:</td>
<td>Its:</td>
</tr>
<tr>
<td>(Address)</td>
<td>(Address)</td>
</tr>
<tr>
<td>(City, State and Zip Code)</td>
<td>(City, State and Zip Code)</td>
</tr>
<tr>
<td>(Telephone)</td>
<td>(Telephone)</td>
</tr>
<tr>
<td>(Facsimile Number)</td>
<td>(Facsimile Number)</td>
</tr>
<tr>
<td>Tax I.D.</td>
<td>Tax I.D.</td>
</tr>
<tr>
<td></td>
<td>as Agent</td>
</tr>
<tr>
<td></td>
<td>By:</td>
</tr>
<tr>
<td></td>
<td>Its:</td>
</tr>
</tbody>
</table>

Notices to Agent shall be sent to:

[Name]
[Address]
[City, State, Zip]

With Fax Copy to:
[Name]
[Facsimile Number]
SCHEDULE I
TO CASH ESCROW AGREEMENT

PURPOSE AND MANNER OF DEPOSITS

Credit Support provided by Depositor in the form of Cash under the SOCA, all investments of such Cash, and all proceeds of such investments.

All Credit Support in the form of Cash provided by the Depositor shall be deposited in the Account promptly upon receipt by the Agent.

Instructions for transfer of funds into the Account:

_____________________
_____________________
_____________________
_____________________
_____________________
SCHEDULE II
TO CASH ESCROW AGREEMENT

INSTRUCTIONS OF DEPOSITORS

1. Upon written notice signed by the Secured Party to the Agent that one or more of the following events has occurred, Agent shall withdraw Cash in the amount specified in such notice from the Account (as described on Schedule I) and shall transfer such Cash in accordance with the Secured Party’s instructions.

   (a) The Depositor has failed to pay an amount presently due and owing under Section 4.1.2 of the Agreement, which amount remains outstanding.

   (b) An Event of Default (as defined in the SOCA) or a Termination Event (as defined in the SOCA) with respect to the Depositor has occurred and is continuing, and the Depositor owes the Secured Party a specified amount in respect of such Event of Default, which amount remains outstanding.

   (c) An Early Termination Date (as defined in the SOCA) has occurred or been designated as a result of an Event of Default or a Termination Event (as defined in the Agreement) and a specified amount of the Termination Payment (as defined in the SOCA) owed by the Depositor to the Secured Party remains outstanding.

2. Upon written notice signed by both the Secured Party and the Depositor that the Depositor has replaced a specified amount of Cash in the Account with a Letter of Credit (as defined in the SOCA), the Agent shall withdraw such amount of Cash from Depositor’s Subaccount and transfer such Cash in accordance with the Depositor’s instructions.

3. The Agent shall liquidate such Cash Deposit from the Account as may be necessary to meet the withdrawal instructions under paragraphs 1 through 2 of this Schedule II.

7. Authorized persons referred to in Sections 1 and 7 of the Agreement are as specified below, as such names may be amended from time to time by notice to the Agent:

   For Depositor:

   For Secured Party:
SCHEDULE III
TO CASH ESCROW AGREEMENT

PERMITTED INVESTMENTS
SCHEDULE IV
TO CASH ESCROW AGREEMENT
## ATTACHMENT F

### SCHEDULE OF APPROVED STANDARD OFFER CAPACITY PRICES

<table>
<thead>
<tr>
<th>Delivery Year (ending May 31st)</th>
<th>Standard Offer Capacity Price ($/MW-day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td></td>
</tr>
<tr>
<td>2026</td>
<td></td>
</tr>
<tr>
<td>2027</td>
<td></td>
</tr>
<tr>
<td>2028</td>
<td></td>
</tr>
<tr>
<td>2029</td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td></td>
</tr>
<tr>
<td>2031</td>
<td></td>
</tr>
<tr>
<td>2032</td>
<td></td>
</tr>
<tr>
<td>2033</td>
<td></td>
</tr>
</tbody>
</table>
Attachment 2

Prequalification Application Materials
Pre-Qualification Application
New Jersey Long-Term Capacity Agreement Pilot Program

Part A. Applicant General Project Data

Applicant:  
Project Name:  

Project Sponsor(s): List sponsors in space provided here. For each sponsor listed, attach a copy of Attachment 1 with contact information, disclosures, etc.

Primary Contact:  
Name  
Title  
Company  
Postal Address  
Phone  
FAX  
E-mail  

Financing Plan: Using the form of Attachment 2, provide a narrative of how the project will be financed, including contracting legal entity structure, sources of debt, and key supporting agreements.

Team Members: Identify the entity that will provide the indicated scope.

Engineering  
Environmental Permitting  
Major Equipment Supplier(s)  
Construction Management  
Construction  
Operator  
Other (specify role)  

Permitting Plan: Using the form of Attachment 3, provide a narrative of how the environmental and other permits will be managed.

Fuel Plan: Using the form of Attachment 4, provide a narrative of how the fuel will be supplied and delivered.

Operating Plan: Using the form of Attachment 5, provide a narrative of how the project will be operated and maintained.

Community and Economic Benefits: Using the form of Attachment 6, provide a narrative of the project’s local and statewide community and economic benefits.

Project Unforced Capacity (UCAP) in MW (SOCA capacity expected to clear in Base Residual Auction (BRA))  
Project Installed Capacity in MW (Nameplate Rating)  
Target Commercial Operation Date  
Attach a supporting Project Schedule with Milestones  
Year of Planned First BRA Offer (e.g., 2011 for delivery year ending May 31, 2015)  
Street Address of Project: (Also, attach a map showing site location and boundaries)  
Point of Electric Interconnect and Substation Owner  
PJM Interconnection Queue Number  
Status of Electrical Interconnection Process  
Expected Date of Execution of Interconnection Service Agreement  
Source of Cooling and Makeup Water  
Water Discharge Point(s)  

Technology:  
Generation Type (CCGT, SCGT, STG, etc.)  
Primary Fuel Type (e.g., natural gas, wind, wood chips)  
Secondary Fuel Type (if applicable)  
Natural Gas Pipeline Connection (if applicable)  
On-Site fuel storage capacity (if applicable)  
Emissions Control Type(s)  
Resource Category (1=Dispatchable, 2=Variable Energy)  

For Dispatchable Resources:
Complete worksheet "DispatchableOpData"  

For Variable Energy Resources:
Complete worksheet "VariableEnergyOpData"  

Category Unspecified
### Pre-Qualification Application
#### Part B1. Operating Data Sheet for Dispatchable Resource

Yellow shaded cells are input cells.

<table>
<thead>
<tr>
<th>Applicant:</th>
<th>Specify on AppData Sheet</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Name:</td>
<td>Specify on AppData Sheet</td>
</tr>
</tbody>
</table>

| Parameter | Specification
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation Type (CCGT, SCGT, STG, etc.)</td>
<td></td>
</tr>
<tr>
<td>Primary Fuel Type</td>
<td></td>
</tr>
<tr>
<td>Secondary Fuel Type</td>
<td></td>
</tr>
<tr>
<td>Natural Gas Pipeline Connection (if applicable)</td>
<td></td>
</tr>
<tr>
<td>Heat Rejection Type (e.g., Evap. Clg. Twr., Air Cooled Cndnsr.)</td>
<td></td>
</tr>
<tr>
<td>Water Intake Rate (Mil. Gal./Day)</td>
<td></td>
</tr>
<tr>
<td>Water Discharge Rate (Mil. Gal./Day)</td>
<td></td>
</tr>
<tr>
<td>Prime Mover (GT or Engine) Model</td>
<td></td>
</tr>
<tr>
<td>Configuration (e.g., 2 x 1 for CCGT with 2 GTs, 1 ST)</td>
<td></td>
</tr>
<tr>
<td>Number of Dispatchable Units</td>
<td></td>
</tr>
<tr>
<td>Nominal Capacity per Dispatchable Unit (MW)</td>
<td></td>
</tr>
<tr>
<td>Installed Capacity (MW) from AppData worksheet</td>
<td></td>
</tr>
<tr>
<td>Total Net Summer Capacity (MW) (New and clean)</td>
<td></td>
</tr>
<tr>
<td>Total Net Winter Capacity (MW) (New and clean)</td>
<td></td>
</tr>
<tr>
<td>Expected Variable Operating Cost ($/MWh) (in 2011 dollars)</td>
<td></td>
</tr>
<tr>
<td>Minimum Down Time (Hrs)</td>
<td></td>
</tr>
<tr>
<td>Minimum Run Time (Hrs)</td>
<td></td>
</tr>
<tr>
<td>Cold Start-up Time (Hrs) (if applicable)</td>
<td></td>
</tr>
<tr>
<td>Cold Start Minimum Down Time (Hrs)</td>
<td></td>
</tr>
<tr>
<td>Fuel per unit start on primary fuel (MMBtu)</td>
<td></td>
</tr>
<tr>
<td>Fuel per unit start on secondary fuel (MMBtu)</td>
<td></td>
</tr>
<tr>
<td>Shut-down Time (Min)</td>
<td></td>
</tr>
<tr>
<td>Ramp-up rate (MW/Minute)</td>
<td></td>
</tr>
<tr>
<td>Ramp-down rate (MW/Minute)</td>
<td></td>
</tr>
<tr>
<td>Black Start Capability (Yes or No)</td>
<td></td>
</tr>
<tr>
<td>Automatic Generation Control Capability (Range in MW)</td>
<td></td>
</tr>
<tr>
<td>Type of Fuel in On-Site Fuel Storage, units. (if applicable, e.g., ULSD, gal.)</td>
<td></td>
</tr>
<tr>
<td>On-Site Fuel Storage Capacity (units as specified above)</td>
<td></td>
</tr>
<tr>
<td>Limitations on Secondary Fuel use (if applicable)</td>
<td></td>
</tr>
<tr>
<td>Expected Forced Outage Rate</td>
<td></td>
</tr>
<tr>
<td>Summer Period: June - September (%)</td>
<td></td>
</tr>
<tr>
<td>Winter Period: October - May (%)</td>
<td></td>
</tr>
<tr>
<td>Planned Outage Time (average days per year)</td>
<td></td>
</tr>
</tbody>
</table>
### Pre-Qualification Application
#### Part B1. Operating Data Sheet for Dispatchable Resource

**Resource Category not specified on AppData worksheet**

<table>
<thead>
<tr>
<th>Applicant:</th>
<th>Specify on AppData Sheet</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Name:</td>
<td>Specify on AppData Sheet</td>
</tr>
</tbody>
</table>

#### Heat Rates to be specified as new and clean

<table>
<thead>
<tr>
<th>Unit Operating Set Points - Summer 90°F, Primary Fuel</th>
<th>Net Output (MW)</th>
<th>Net Plant Heat Rate (BTU/kwh)</th>
<th>NOx (lb/MMBtu)</th>
<th>SO2 (lb/MMBtu)</th>
<th>CO2 (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Load 90°F (100%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Load 90°F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Unit Operating Set Points - Winter 20°F, Primary Fuel</th>
<th>Net Output (MW)</th>
<th>Net Plant Heat Rate (BTU/kwh)</th>
<th>NOx (lb/MMBtu)</th>
<th>SO2 (lb/MMBtu)</th>
<th>CO2 (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Load 20°F (100%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Load 20°F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Unit Operating Set Points - ISO Conditions, Primary Fuel</th>
<th>Net Output (MW)</th>
<th>Net Plant Heat Rate (BTU/kwh)</th>
<th>NOx (lb/MMBtu)</th>
<th>SO2 (lb/MMBtu)</th>
<th>CO2 (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Load 59°F (100%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Load 59°F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Heat Rates to be specified as new and clean

<table>
<thead>
<tr>
<th>Unit Operating Set Points - Summer 90°F, Secondary Fuel</th>
<th>Net Output (MW)</th>
<th>Net Plant Heat Rate (BTU/kwh)</th>
<th>NOx (lb/MMBtu)</th>
<th>SO2 (lb/MMBtu)</th>
<th>CO2 (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Load 90°F (100%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 90°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Load 90°F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Unit Operating Set Points - Winter 20°F, Secondary Fuel</th>
<th>Net Output (MW)</th>
<th>Net Plant Heat Rate (BTU/kwh)</th>
<th>NOx (lb/MMBtu)</th>
<th>SO2 (lb/MMBtu)</th>
<th>CO2 (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Load 20°F (100%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 20°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Load 20°F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Unit Operating Set Points - ISO Conditions, Secondary Fuel</th>
<th>Net Output (MW)</th>
<th>Net Plant Heat Rate (BTU/kwh)</th>
<th>NOx (lb/MMBtu)</th>
<th>SO2 (lb/MMBtu)</th>
<th>CO2 (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Load 59°F (100%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Part Load 59°F ( )</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Load 59°F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Part B2. Operating Data Sheet for Variable Energy Resource

### Resource Category not specified on AppData worksheet

<table>
<thead>
<tr>
<th>Applicant:</th>
<th>Specify on AppData Sheet</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Name:</td>
<td>Specify on AppData Sheet</td>
</tr>
</tbody>
</table>

- **Source of Energy (e.g. Wind, Solar)**
- **Unit (WTG, PV module, etc.) Mfr. and Model**
- **Nominal Capacity per Unit (MW)**
- **Number of Units**
- **Total Installed Capacity (MW)**
- **Installed Capacity from AppData worksheet**
- **Expected unit availability (%)**
- **Expected Output, MWh**
  - Summer (June-September P50)
  - Winter (October-May P50)

### Expected (P50) Net Capacity Factor - Before outage losses but after collection efficiency and parasitic losses

(Hourly MWh / installed MW)

#### Days per month

<table>
<thead>
<tr>
<th>Month</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
</tr>
</thead>
<tbody>
<tr>
<td>Days</td>
<td>30</td>
<td>31</td>
<td>31</td>
<td>30</td>
<td>30</td>
<td>31</td>
<td>31</td>
<td>28</td>
<td>31</td>
<td>30</td>
<td>31</td>
<td></td>
</tr>
</tbody>
</table>

#### Hour of Day

- **Off-Peak**
  - HE0100
  - HE0200
  - HE0300
  - HE0400
  - HE0500
  - HE0600
  - HE0700
- **On-Peak**
  - HE0800
  - HE0900
  - HE1000
  - HE1100
  - HE1200
  - HE1300
  - HE1400
  - HE1500
  - HE1600
  - HE1700
  - HE1800
  - HE1900
  - HE2000
  - HE2100
  - HE2200
  - HE2300
  - HE2400

#### Off-Peak

- Off-Peak: 24
- WkEnd Off Peak (All hours): 0.00%
- WkDay Off Peak (HE2400 thru HE0700): 0.00%
- WkDay On Peak (HE0800 thru HE2300): 0.00%

#### Seasonal

- **Summer (Jun-Sep)**
  - 0.00%
- **Winter (Oct-May)**
  - 0.00%

#### Full Year

- 0.00%
<table>
<thead>
<tr>
<th>Applicant:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Name:</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sponsor Name</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Legal Form of Sponsor</td>
<td></td>
</tr>
<tr>
<td>State of Registration</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sponsor Contact</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Name</td>
<td></td>
</tr>
<tr>
<td>Title</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Postal Address</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Phone</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Email Address</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Sponsor Officers, Directors, Partners</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Project Development Experience</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Other Generation Assets</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(indicate % ownership)</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Under development</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Under construction</td>
<td></td>
</tr>
<tr>
<td>In operation</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Guarantor (if applicable)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term unsecured debt credit rating of sponsor or guarantor</td>
<td></td>
</tr>
</tbody>
</table>

| Disclosure of any instance in which sponsor, its officers, directors, or partners have been convicted of any crime related to the sale or purchase of power, generating assets, transmission, or other energy products or services. |   |

| Disclosure of any instance in which sponsor or its parent company has incurred US EPA or NJ DEP environmental regulation violations. |   |

| Disclosure of any instance in which sponsor or its parent company has incurred US OSHA workplace safety or health violations. |   |

<p>| Attach most recent audited financial statements. Indicate here period covered. |   |</p>
<table>
<thead>
<tr>
<th><strong>Proposed Contracting Entity</strong></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Legal Form of Entity</strong></td>
<td></td>
</tr>
<tr>
<td><strong>State of Registration</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Ownership Structure</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Sources of Debt</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Key Supporting Agreements</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Identify here and attach any letters showing interest from lenders and equity participants</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Other Relevant Information</strong></td>
<td></td>
</tr>
</tbody>
</table>
## Pre-Qualification Application
### Attachment 3 to Part A – Permitting Plan

<table>
<thead>
<tr>
<th>Applicant:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Name:</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Site Control (describe status)</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>List of all permits and achieved or expected approval dates</th>
<th></th>
</tr>
</thead>
</table>

<p>| Description of any environmental benefits attributable to Project |  |</p>
<table>
<thead>
<tr>
<th>Applicant:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Name:</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Primary Fuel Type</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Source of Fuel, Arrangements</td>
<td></td>
</tr>
<tr>
<td>Transportation Arrangements</td>
<td></td>
</tr>
<tr>
<td>Local Delivery Arrangements (if applicable)</td>
<td></td>
</tr>
<tr>
<td>Estimated delivery charges</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Secondary Fuel Type (if applicable)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage capacity (liquids)</td>
<td></td>
</tr>
<tr>
<td>Delivery arrangements</td>
<td></td>
</tr>
<tr>
<td>Proposed Operator</td>
<td>Relevant experience</td>
</tr>
<tr>
<td>-------------------</td>
<td>--------------------</td>
</tr>
<tr>
<td>Scope of responsibility</td>
<td></td>
</tr>
<tr>
<td>PJM energy market participation experience</td>
<td></td>
</tr>
<tr>
<td>PJM capacity market (RPM/BRA) participation experience</td>
<td></td>
</tr>
<tr>
<td>Applicant:</td>
<td></td>
</tr>
<tr>
<td>----------------------------------------</td>
<td>-----------------------------------</td>
</tr>
<tr>
<td>Project Name:</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Location of Project</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Property tax rates and plant assessed value for first three operating years, OR Schedule of Payments in Lieu of Taxes for duration of PILOT</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Describe and quantify any upfront community grants or infrastructure improvements that will be paid for as part of project development</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Identify here and attach any letters of support from community leaders</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Describe and quantify the approximate on-site construction budget for materials, supplies, and services ($ million, by construction year)</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Describe any plans for maximizing the shares of locally-procured (i.e., within the community and New Jersey) construction materials, supplies, or services, and local construction-related workers</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Construction period (months)</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Estimated construction payroll ($ million, by construction year)</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Estimated construction jobs (FTE), by construction year</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Estimated portion of construction workers who live locally (daily commuters)</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Estimated operations payroll ($ million for first operating year)</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Estimated operations jobs (FTE)</th>
<th></th>
</tr>
</thead>
</table>

---

1 One full-time equivalent (FTE) construction-related job is defined as 1,820 hours per year.

2 One full-time equivalent (FTE) operations job is defined as 1,820 hours per year.
| Estimated portion of operations jobs to be filled by workers who live locally (daily commuters) |  |
STATE OF NEW JERSEY  
Board of Public Utilities  
Two Gateway Center, Suite 801  
Newark, NJ 07102  
www.nj.gov/bpu/  

ENERGY  

IN THE MATTER OF THE LONG-TERM CAPACITY AGREEMENT PILOT PROGRAM  
) ORDER  
) DOCKET NO. EO11010026  

(SERVICE LIST ATTACHED)  

BY THE BOARD:  

On January 28, 2011, Governor Chris Christie signed into law P.L. 2011, c.9, amending and supplementing P.L. 1999, c. 23, which law establishes a long-term capacity agreement pilot program ("LCAPP") to promote the construction of qualified electric generation facilities, hereinafter referred to as the LCAPP Law.¹ Pursuant to the LCAPP Law, on February 10, 2011, the New Jersey Board of Public Utilities ("Board") initiated this proceeding and also approved the retention, as recommended by the electric distribution utilities ("EDCs"), of an agent ("LCAPP Agent") to assist the Board in this proceeding.²  

BACKGROUND:  

Pursuant to the LCAPP Law, the Board was mandated to immediately commence a proceeding to establish an LCAPP.³ The LCAPP is intended to seek offers for financially-settled Standard Offer Capacity Agreements ("SOCAs") with eligible generators.⁴ The LCAPP Law requires selected eligible generators, with Board approved and executed SOCAs, to participate in and be accepted as a capacity resource in the base residual auction conducted by PJM.⁵  

¹ The provisions of the LCAPP Law have been codified in the following sections of the New Jersey Statutes: N.J.S.A. 48:3-51, 48:3-60.1, 48:3-98.3—98.4.  
² N.J.S.A. 48:3-98.3(b).  
³ N.J.S.A. 48:3-98.3(a).  
⁴ "Eligible generator" means a developer of a base load or mid-merit electric power generation facility including, but not limited to, an on-site generation facility that qualifies as a capacity resource under PJM criteria and that commences construction after 1/28/2011. N.J.S.A. 48:3-51.  
⁵ N.J.S.A. 48:3-98.3(a).
The Board was further required to approve the retention of an agent, recommended by the EDCs, to assist the Board in administering the LCAPP.\(^6\) The LCAPP Agent, retained in accordance with the LCAPP Law,\(^7\) shall, on behalf of the Board, be responsible for:

1. Assisting the Board with the establishment of the LCAPP that allows for developing and offering financially-settled SOCAs for the purpose of facilitating the development of eligible generators;

2. Pre-qualifying eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date; and

3. Recommending to the Board its selection of winning eligible generators based on the net benefit to ratepayers of each pre-qualified eligible generator’s offer price and term. Eligible generators that can enter commercial operation for energy delivery year 2015 are to be provided with a weighted preference in addition to the net benefit ratepayer test. Eligible generators shall also indicate the amount of capacity they are offering in the LCAPP.

Accordingly, the Board, at its February 10, 2011, Agenda Meeting, initiated the instant proceeding to fulfill the requirements of the LCAPP Law. At that Agenda Meeting, the Board adopted a schedule and also approved the LCAPP Agent, Levitan & Associates, Inc., as recommended by the EDCs, and named President Solomon as Presiding Officer.

THE PUBLIC HEARINGS

The LCAPP law required the Board to conduct public hearings. N.J.S.A. 48:3-98.3(c) To comply with this provision, the Board held four (4) public hearings throughout the State, one in each of the service territories of the EDCs. The public hearings were open to members of the public to allow comment on the Board’s LCAPP proceeding as well as on the proposed recovery through electric distribution rates of costs resulting from the LCAPP. After publication of notice, the public hearings were presided over by President Solomon, and were conducted on the following dates and locations:

A public hearing was held in the Rockland Electric Company ("Rockland") service territory on March 11, 2011 at 10:00 AM in the Township of Mahwah Court Room, 475 Corporate Drive, Mahwah, NJ 07430. At the Rockland public hearing, statements were made by the Director, Division of Rate Counsel and Rockland. No members of the public appeared.

A public hearing was held in the Public Service Electric and Gas Company ("PSE&G") service territory on March 15, 2011 at 1:00 PM at the Board’s hearing room, 44 South Clinton Avenue - 1st Floor, Trenton, NJ 08625. At the PSE&G public hearing, statements were made by the

\(^6\) N.J.S.A. 48:3-98.3(b).
\(^7\) Id.
Director, Division of Rate Counsel, PSE&G, the Old Bridge Town Council and the Sierra Club, New Jersey Chapter. No other members of the public appeared.

A public hearing was held in the Jersey Central Power & Light Company ("JCP&L") service territory on March 16, 2011 at 1:00 PM in the Morris County Administration & Records Building, Public Meeting Room - 5th Floor, 2123 Court Street, Morristown, NJ 07963. At the JCP&L public hearing, statements were made by the Director, Division of Rate Counsel, and JCP&L. No members of the public appeared.

A public hearing was held in the Atlantic City Electric Company ("ACE") service territory on March 17, 2011 at 1:00 PM in the Atlantic County Library/West (Hammonton Branch), 451 Egg Harbor Road, Hammonton, NJ 08037. At the ACE Public Hearing, statements were made by the Director, Division of Rate Counsel, and ACE. No members of the public appeared.

The Board’s February 10, 2011 ("February 10 Order") also provided for the submission of written or electronic comments by the public sent to the attention of the Office of the Secretary at: Board of Public Utilities, Two Gateway Center, Suite 801, Newark, NJ 07102 postmarked no later than March 18, 2011 or to board.secretary@bpu.state.nj.us by that same date. The Board’s Office of the Secretary received 2 comments from the public.

**THE LCAPP PROCEEDING**

As previously stated, the Board’s February 10 Order initiating the instant proceeding adopted, among other things, specific milestones to be achieved. The LCAPP Agent undertook the following activities to achieve the milestones:

---

The following milestones are set forth at page 5 of the Board’s February 10, 2011 Order:

- Proposed SOCA Submission: Monday, 2/14/2011
- Application Data Sheets Issued by Agent: Tuesday, 2/15/2011
- Application Data Sheets Due: Tuesday, 2/22/2011
- Initial Comments to Proposed Form of SOCA: Tuesday, 2/22/2011
- Reply Comments to Proposed Form of SOCA: Friday, 2/25/2011
- Final Form of SOCA Issued: Tuesday, 3/1/2011
- Final SOCP Bids Due: Monday, 3/7/2011
- Initial Recommended SOCA Proposals: Tuesday, 3/15/2011
- Public Comments on Agent’s Report: Thursday, 3/24/2011
- Board Order on Recommended SOCAs: Wednesday, 3/30/2011

Note that the Board Order on Recommended SOCAs was initially stated as a March 30, 2011 milestone and was changed to March 29, 2011 to comply with the sixty day (60) requirement set forth in the LCAPP Law.
On February 10, 2011, the LCAPP website (www.nj-lcapp.com), administered by the LCAPP Agent, was activated. The Agent's website served as a document repository and information portal for the LCAPP process for eligible generators and other interested parties.

On February 11, 2011, a form was developed by the Agent to assist interested parties in submitting a proposed SOCA, was posted on the LCAPP website. Also on this date, the Board's Order Initiating the Proceeding and Approving the Agent was posted on the LCAPP website as well as on the Board's website.

On February 14, 2011, application Data Sheets and other prequalification materials, developed by the Agent, in consultation with Board Staff, were posted on the LCAPP website. This was one day ahead of schedule for this key milestone.

Also, on February 14, 2011, proposed forms of the SOCA, as well as comments regarding the SOCA, were submitted by interested parties. These documents were posted for review and comment on the LCAPP website as well as on the Board's website.

On February 18, 2011, the EDCs collectively submitted proposed terms of security to be included in the SOCA (security agreement and escrow agreement). These documents were posted on the LCAPP website for review and comment.

On February 22, 2011, entities interested in participating in the LCAPP proceeding submitted pre-qualification application data sheets detailing their respective electric generation units to be evaluated by the Agent.

Also on February 22, 2011, Initial Comments to the proposed forms of SOCA were submitted by interested parties and were subsequently posted on the LCAPP website as well as the Board's website for public review and comment.

On February 23, 2011, a Standard Offer Capacity Price ("SOCP") Bid Form and an Officer Certification Form required for bid submission, were posted on the LCAPP website. Information regarding Bid Letters of Credit, including Forms and Instructions, was also posted on the LCAPP website.

Also on February 23, 2011, the LCAPP Agent's Initial Draft SOCA was posted on the LCAPP website for public review and comment. Although not a milestone in the Board's February 10, 2011 Order, to afford the public and interested parties an opportunity to review and comment on the SOCA before final issuance, an initial draft of the proposed SOCA was posted on the LCAPP website.

On February 25, 2011, Reply Comments to the proposed forms of SOCA submitted on February 14, 2011, as well as comments on the Agent's Initial Draft SOCA, were submitted by interested parties and subsequently posted on the LCAPP website and the Board's website.

---

9 Submissions were made by the following entities: the electric distribution companies ("EDCs"), Division of Rate Counsel, Exelon, Hess Corp., LS Power, Competitive Power Ventures ("CPV"). GenOn Energy, and NRG Energy Inc.

10 34 applications were received totaling approximately 7500 MWs. Several entities submitted multiple applications for different generating units.

11 Submissions were made by the following entities: the EDCs, Division of Rate Counsel, Exelon, Hess
On February 27, 2011, the security-related documents, namely, the security agreement and escrow agreement, submitted by the EDCs in their reply comments, were posted on the LCAPP website for review and comment.

Again, although not required by the Board’s February 10 Order, to afford the public and interested parties an additional opportunity to review and comment on the SOCA before final issuance, on February 28, 2011, a revised Draft SOCA was posted on the LCAPP website for public review and comment.

On March 1, 2011, after review of all of the comments, the final proposed SOCA was posted on the LCAPP website and subsequently on the Board’s website.

Also on March 1, as set forth in the Board’s February 10 Order, the EDCs collectively submitted a proposed rate recovery mechanism.

On March 7, 2011, entities that previously submitted pre-qualification applications submitted their binding bid price and term to be evaluated by the Agent, along with the Officer Certification Form and Bid Letter of Credit. The Agent, through the LCAPP website and the electronic subscriber service list, informed all interested parties that the bids submitted by interested generators must conform to the final proposed form of SOCA, except for minor technical corrections. All eligible generators were on notice that any bid predicated on a substantive modification to the final proposed form of SOCA would not be considered by the Agent. Bids predicated on substantial revisions to the final proposed form of SOCA would make it impossible for the Agent to reasonably compare a generator(s) non-conforming bid(s) submitted with the conforming bid(s) submitted by the other generators.

Eighty (80) questions regarding the proceeding, as well as many technical questions, have been answered by the Agent to provide guidance to interested parties. These questions and answers were posted on the LCAPP website in a timely manner so that the information was available to all interested parties simultaneously.

On March 15, 2011, the LCAPP Agent’s recommended selection of qualified bidders was submitted to the Board. The Agent’s recommended selection was posted on the LCAPP website as well as on the Board’s website.

On March 21, 2011, the Agent’s Report supporting the selection of qualified bidders setting forth the detailed analysis supporting the Agent’s selection of qualified bidders was submitted to the Board. The Agent’s Report was posted on the LCAPP website as well as on the Board’s website for public review and comment.


12 LCAPP Question No. 64: Will non-conforming bids that are conditioned on modification(s) to the March 1, 2011 SOCA, including modifications that were previously submitted through the comment process, be considered or rejected outright? Any bid predicated on a substantive modification to the Final Proposed Form SOCA dated March 1, 2011, will not be considered. Bids that identify technical corrections merely for consistency sake to the Final Proposed Form SOCA will be considered, however. This response was posted on the LCAPP website on March 4, 2011.
On March 25, 2011, nine comments regarding the Agent's Report were submitted by interested parties.

**APPROVAL OF THE FORM OF THE SOCA**

The SOCA, as defined in the LCAPP Law, is a financially settled transaction agreement that allows eligible generators to receive payments from or make payments to the EDCs for a defined amount of electric capacity for a term specified by the Board not to exceed fifteen (15) years. Pursuant to the LCAPP law, these payments are implemented through a fully non-bypassable irrevocable charge.\(^\text{13}\)

The Board's February 10 Order directed interested parties to submit proposed forms of the SOCA for the LCAPP Agent's and the Board's consideration. On February 14, 2011 the Board received SOCA submissions from several interested parties, as well as comments regarding the SOCA.\(^\text{14}\) Subsequently, on February 18, 2011, the EDCs collectively submitted proposed terms of security to be included in the SOCA (security agreement and escrow agreement).

On February 22, 2011, Initial Comments to the proposed forms of SOCA were submitted by interested parties. On February 23, 2011, the LCAPP Agent's Initial Draft SOCA was posted on the LCAPP website for public review and comment. Although not a milestone in the Board's February 10, 2011 Order, to afford the public and interested parties an opportunity to review and comment on the SOCA before final issuance, an initial draft of the proposed SOCA was posted on the LCAPP website.

On February 25, 2011, Reply Comments to the proposed forms of SOCA submitted on February 14, 2011, as well as comments on the Agent's Initial Draft SOCA, were submitted by interested parties\(^\text{15}\) and subsequently posted on the LCAPP website and the Board's website.

On February 27, 2011, the security-related documents, namely, the security agreement and escrow agreement, submitted by the EDCs in their reply comments, were posted on the LCAPP website for review and comment.

Again, although not required by the Board's February 10, 2011 Order, to afford the public and interested parties an additional opportunity to review and comment on the SOCA before final issuance, on February 28, 2011, a revised Draft SOCA was posted on the LCAPP website for public review and comment.

On March 1, 2011, a Final Proposed Form of SOCA was posted on the LCAPP website and the Board's website. Subsequently, several parties submitted substantive comments on the Final Proposed Form of SOCA. Some potential eligible generators raised concerns expressing their belief that the some of the terms and conditions of the final proposed form of SOCA, as well as the initial draft and revised draft SOCA, would not be acceptable to a financial lender and

\(^{13}\) N.J.S.A. 48:3-51.

\(^{14}\) Submissions were made by the following entities: the EDCs, Division of Rate Counsel, Exelon, Hess Corp., LS Power, Competitive Power Ventures (CPV), GenOn Energy, and NRG Energy Inc.

\(^{15}\) Submissions were made by the following entities: the EDCs, Rate Counsel, Exelon, Hess Corp., LS Power, CPV, NextEra Energy Resources, and NRG Energy Inc.
therefore, the potential new generation project would not be able to obtain financing to construct the facility. These potentially eligible generators also maintained that the final proposed form of SOCA, as well as the initial draft and revised draft SOCA, did not comport with the LCAPP Law regarding irrevocability of the SOCA. The EDCs, on the other hand, believed that the final proposed form of SOCA, as well as the initial draft and revised draft SOCA, did not comport with the LCAPP Law for other reasons. The EDCs argued for terms and conditions that would automatically terminate the SOCA, including, but not limited to, failure of a SOCA recipient to clear in the first Base Residual Auction ("BRA") it bid into. The EDCs along with their substantive comments, submitted technical modifications to the Final Proposed Form of SOCA. These technical modifications were primarily limited to incorrect paragraph cross references and definition references. Rate Counsel submitted comments on the terms and conditions of the final proposed form of SOCA, as well as on the initial draft and revised draft SOCA. Based upon a review of all the comments received on the initial draft and revised draft SOCA, Board Staff believes that the final proposed form of SOCA strikes a fair and reasonable balance regarding the issues and concerns raised by all the interested parties.

DISCUSSION AND FINDING

As noted above, parties have taken issue with the provisions that allow a SOCA to continue even if the generator does not clear the BRA after achieving the Commencement Date, that allow modification of the SOCA under certain circumstances, and that terminate the SOCA if the LCAPP Law is voided or a change in the law makes performance under the SOCA illegal. The Board HEREBY FINDS that these provisions do not violate the LCAPP Law or the law of this State. While it is true that N.J.S.A. 48:3-98.3(c)(12) requires that eligible generators with executed SOCA must participate in and clear the annual BRA, the statute does not dictate the ramifications for failure to clear the BRA. The proposed final form of the SOCA allows the contract to continue but ratepayers do not pay anything under that scenario, and the potential benefit if the generator does clear in a succeeding BRA is preserved. Objectants claim that allowing any modification of the SOCA violates N.J.S.A. 48:3-98.3(f) which bars the Board and other governmental agencies from modifying or amending a SOCA after approval. But the proposed form of the SOCA only provides for modifications on consent of the parties with Board approval only after the parties reach an agreement, and thus these modifications do not violate the Act. Finally, the provision terminating the SOCA in the event of certain changes in the law is only intended to provide some degree of certainty in a situation that is beyond the control of the Board, and reflects the basic and fundamental understanding that the Board can not and should not indicate a commitment to a course of action if the legislative or judicial branch finds that action illegal or incorrect.

Based upon the Board's review of the Final Proposed Form of SOCA, and the comments submitted, the Board HEREBY ACCEPTS AND APPROVES the Final Proposed Form of SOCA, modified to incorporate the technical corrections set forth in the EDCs comments dated March 4, 2011. The Board agrees with the LCAPP Agent that the Final SOCA appropriately balances the risks between ratepayers and generators while satisfying the expressed goals of the LCAPP Law, and respecting other principles of the law of this State. See Wilentz v. Hendrickson, 135 N.J. Eq. 244 (1944); Gallenthin Realty Dev., Inc. v. Paulsboro, 191 N.J. 344 (2007).
AGENT'S RECOMMENDATION OF QUALIFIED ELIGIBLE GENERATORS AND COMMENTS

THE LCAPP AGENT'S REPORT

After evaluating the conforming SOCP bids, the Agent identified three qualified generation facilities to be recommended for SOCA awards, with a total unforced capacity ("UCAP") of 1,948.5 MW, as follows:

<table>
<thead>
<tr>
<th>Sponsor</th>
<th>Newark Energy Center</th>
<th>Old Bridge Clean Energy Center</th>
<th>Woodbridge Energy Center</th>
</tr>
</thead>
<tbody>
<tr>
<td>UCAP</td>
<td>625.0 MW</td>
<td>660.1 MW</td>
<td>663.4 MW</td>
</tr>
<tr>
<td>Location</td>
<td>Newark, NJ</td>
<td>Old Bridge, NJ</td>
<td>Woodbridge, NJ</td>
</tr>
<tr>
<td>Technology Type</td>
<td>Combined Cycle</td>
<td>Combined Cycle</td>
<td>Combined Cycle</td>
</tr>
<tr>
<td>Fuel Type</td>
<td>Natural Gas</td>
<td>Natural Gas</td>
<td>Natural Gas</td>
</tr>
<tr>
<td>First SOCA Year</td>
<td>2016-2017</td>
<td>2015-2016</td>
<td>2015-2016</td>
</tr>
</tbody>
</table>

The LCAPP Agent has determined that the recommended SOCA portfolio of the Newark Energy Project, Old Bridge Clean Energy Center, and Woodbridge Energy Center (the recommended SOCA portfolio) offers substantial net economic benefits on an expected value basis over the relevant planning horizon to New Jersey's electric customers. These net economic benefits are ascribable to the expected value of the SOCA portfolio in relation to the forecasted capacity market clearing price under PJM's Base Residual Auction ("BRA"), as well as the reduction in wholesale energy prices in New Jersey, all other things being the same. In addition, other economic benefits may be realized, but have not been counted.

The Agent has determined that the recommended SOCA portfolio offers substantial socio-economic benefits to the State of New Jersey on an expected value basis. These benefits are primarily due to the expansion of direct employment for the duration of the associated construction phases of the projects, and the new on-site permanent jobs associated with operation and maintenance of the new generation facilities during their operating lives. In addition, employment and incomes are expected to increase due to the indirect impacts of increasing the demand for goods and services procured from New Jersey firms during the construction and operations phases, giving rise to what is known as an economic multiplier effect. Though not quantified, an additional economic benefit to New Jersey's electric customers is the expected reduction in wholesale power costs which would be passed on to electric customers, giving rise to increased expenditures on other goods and services.

---

16 LCAPP Agent Report, Sec. 7.1 at 71.
17 LCAPP Agent Report, Sec. 7.2 at 72 - 78.
18 Id. at 76-78.
The Agent has determined that the recommended SOCA portfolio also offers significant environmental benefits to New Jersey’s electric customers. These environmental benefits result from the displacement of incumbent generation with the portfolio of cleaner, gas-fired generation, resulting in lower net emissions of NOx, SO2, and mercury across the PJM region, much of which is upwind of New Jersey. In addition, two of the three projects, the Newark Energy Center and the Woodbridge Energy Center, will be located on brownfield sites. The beneficial reuse of formerly impaired properties represents a significant environmental benefit that may ultimately confer additional economic benefits as well.

COMMENTS ON THE AGENT’S REPORT

As previously noted, on March 24, 2011, nine comments from various interested parties were received regarding the Agent’s Report dated March 21, 2011. The following is a summary of each interested party’s comments:

Middlesex Power Partners (“Middlesex”):

Middlesex believes that the Agent should continue the solicitation process by allowing the four leading projects to adjust their proposed MWs downward by an identical percentage such that the total procurement is precisely 2,000 MW. According to Middlesex, a total of 2,000 MWs is required by the LCAPP law.

Middlesex further believes that the Agent should identify the proposed equipment manufacturer for each recommended project and should recommend projects with diverse major equipment manufacturers. Diversification among major equipment suppliers and proposed turbine models is a key risk mitigation strategy which should be addressed when finalizing the recommended projects. Middlesex asserts that this evaluation does not appear in the Agent’s report.

NextEra:

NextEra asserts that the LCAPP Act requires that eligible generators with executed SOCA shall participate in and clear the annual base residual auction conducted by the PJM as part of its reliability pricing model for each delivery year of the entire term of the agreement. NextEra agrees with the EDCs and argues that this statutory requirement is unambiguous and thus cannot be changed through interpretation, such as the Agent presumes to do by allowing the SOCA to continue but without any payment to the generator.

---

19 Id. at 72-76
20 Comments were received from the following entities: the EDCs, Rate Counsel, PSEG Power, NextEra Energy Resources, West Deptford Energy, Exelon, Middlesex Power Partners, Rockland Capital and Township of West Deptford.
21 This summary is intended for informational purposes only and is not a verbatim recitation of each party’s comments.
PSEG Power:

According to PSEG Power, the Agent failed to support its prequalification decisions. The Agent disqualified nearly two thirds of the prequalification applicants because they were tied to existing generation units and therefore, according to the Agent, did not meet the condition of being a new generation facility. The LCAPP Law did not define “generation facility” as a stand-alone generation facility. PSEG Power further asserts that the definition of “eligible generator” does not even use the term “new.” Instead, the definition creates a “new” requirement by requiring that construction commence after the Statute’s enactment. Expansion projects and up-rates require construction of substantial new physical facilities that result in new capacity. According to PSEG Power, the Statute contains no indication that these types of new facilities should be excluded, and their consideration is consistent with allowing any new capacity for which construction commences after the Statute’s enactment.

Rate Counsel:

Rate Counsel is in general agreement with most aspects of the Agent’s report, with an important caveat that Rate Counsel has not had the opportunity to review any of the bids submitted, nor does the report identify the specific SOCA pricing for the selected projects. Rate Counsel understands such information is to be held confidential at the present time. The Agent’s report provides pricing and customer impact information on the winning SOCA projects largely in aggregate form. For that reason, Rate Counsel cannot comment on the individual specific bid evaluation results and project rankings.

Despite this limitation, Rate Counsel notes that the LCAPP process appears at this stage to have met its objective of fostering the construction of approximately 2,000 MW of modern gas-fired combined cycle capacity in the region. According to Rate Counsel, if completed, this will foster the goals identified in the LCAPP legislation, -- a financial hedge on the cost of capacity; customer savings (particularly in the energy market); economic development/ fiscal benefits (since all three new projects are to be sited in New Jersey); enhanced reliability from 2,000 MW of physical new capacity that likely would not otherwise have been built; and environmental benefits from displacement of other “dirtier” sources of electric generation in the region. The addition of these new generation sources (if constructed) will also enhance the competitiveness of power supply markets by creating market entry. Rate Counsel states that there were two notable observations from the Agent’s analysis. The first is that over the 15 year SOCA contract lives, the RPM credit will fully offset the SOCA payments to the three generators. This demonstrates that, at least on an expectational basis and given the Agent’s assumptions that the SOCAs will function as a financial capacity hedge for both the developers and consumers—not as a “subsidy” as had been incorrectly characterized. The financial hedge is clearly needed to facilitate project development. Beyond the capacity hedge, the Agent estimates energy market savings (which appears to be at least in part reduced congestion costs) of roughly $1.8 billion, net present value, for New Jersey customers.
Rockland Capital - BL England:

Rockland Capital believes that its proposed new gas-fired combined cycle generating facility provides substantial and unique benefits to the local community as well as the State at-large, as set forth in its submissions. Unfortunately, according to Rockland Capital while the various unique attributes may have been taken into account during the eligibility and/or prequalification process, there is no indication in the LCAPP Agent’s Report that these substantial and unique benefits were taken into account during the bid evaluation and final project selection process. Nor is there any indication in the LCAPP Agent’s Report that an assessment was performed by the Agent of whether the selected projects could have or would have been developed without a SOCA.

Rockland Capital makes a general observation that all three recommended generators are located in Northeast New Jersey within about 25-30 miles of each other, in a corridor where many gas-fired electric generating facilities, electric transmission and gas transportation facilities currently exist. In that sense, there is very little geographic diversity offered in terms of new generation or incremental economic activity beyond that associated directly with the construction and operation and maintenance of the power plant.

West Deptford Energy - LS Power:

WDE asserts that it has secured all of the necessary real estate rights and obtained all of the major permits and approvals necessary to begin construction of its proposed generating facility. According to WDE, its facility is the only combined cycle facility in New Jersey positioned to start construction in 2011 and achieve commercial operations prior to June 1, 2014. WDE submitted bids for consideration that would enable construction of the WDE to begin this year. Based on information contained within the Agent Report, WDE is the only bidder certain to provide the anticipated benefits beginning in 2014. According to WDE, the bid provided by WDE represents the lowest cost bid received in the LCAPP process whereby, based on the Agent’s Resource Clearing Price (“RCP”) forecast, WDE would essentially pay the electric utilities each and every year of the Standard Offer Capacity Agreement. According to WDE, ratepayers would be expected to receive over $300 million in payments from WDE under the SOCA. WDE states that it is willing to accept this “below market” pricing in exchange for certainty. In addition to receiving over $300 million in direct payments, WDE believes New Jersey will receive significant additional benefits associated with the construction and operation of the WDE’s facility including additional economic, environmental and community benefits. The Agent did not evaluate the bid from WDE due to changes requested by WDE to the proposed form SOCA. According to WDE, these changes are consistent with the LCAPP Law and industry standard agreements including the Basic Generation Service-Fixed Price Supplier Master Agreement used by the EDCs in New Jersey. According to WDE, these changes are necessary to ensure the SOCA remains valid and enforceable, which is a predicate for the SOCA to provide value.

WDE further notes that all of the recommended projects are located within a radius of approximately 20-miles in northern New Jersey. According to WDE, this concentration of plants in such close proximity poses additional risk to completion of the projects and
reduced energy market benefits to the State (energy market benefits become saturated). Selection of WDE provides geographic diversification resulting in a greater likelihood of success for the remaining selected bidders and broader environmental, economic, community and energy market benefits to the State.

WDE asserts that the quantification of net benefits to ratepayers presented in the Agent Report are overstated for both the assumed RCP credit and energy market benefits attributed to each of the recommended projects. This is more pronounced for the second and third recommended projects as fewer benefits are associated with incremental generation. The premise for selection of the third recommended project is flawed to an extent that it is questionable if the project would provide any net benefit to ratepayers.

EDCs:

The EDCs believe the Agent’s Report fails to provide the necessary details to fully evaluate its findings and conclusions. In addition, the Report apparently does not consider all relevant impacts on the net benefits calculation such as the long-term impacts on capacity market prices. The EDCs respectfully submit that the Board should direct the LCAPP Agent to prepare a revised report that provides much needed granularity with respect the analyses performed and the support for the assumptions and forecasts utilized. Furthermore, the EDCs recommend that the Board convene hearings to allow cross-examination of the LCAPP Agent and to allow the presentation of additional expert testimony to validate the Report’s findings and to suggest possible alternatives.

According to the EDCs, if the recommendations set forth in the Report are accepted, New Jersey ratepayers will become obligated to pay up to an amount that the EDCs estimate is in the range of $1.3 billion in net present value obligations (nominally about $2.6 billion), under 15-year contracts based on an incomplete and highly subjective analysis that renders the prospective net benefits speculative at best. The EDCs do not believe that this analysis provides a proper basis upon which to impose such costs on ratepayers.

The LCAPP process was touted by the State as being open and transparent. Yet, if the prices are withheld, then the process will be entirely opaque – lacking disclosure of the amount for which ratepayers will be at risk. Neither the parties nor the public can evaluate the costs and benefits of the program without this information. Were the Board to require the EDCs to sign the SOCA without disclosing the prices of the winning bidders, the Board would be approving a de facto rate increase without providing public notice to customers of a fundamental element impacting that rate increase.

The EDCs note that the actual capacity prices that the Report reflects are extremely speculative. Specifically, The Report indicates an RPM clearing price for New Jersey and the rest of RTO for most of the contract term to be over $300/MW-day. Yet, the capacity prices in RPM have never gone to $300/MW-day. If the Report were to use the RPM clearing price from last years’ auction and used a SOCA price of $300/MW-day, then the total net SOCA cost would increase to over $1.3 Billion. This one change in RPM clearing prices would result in the costs to ratepayers going from the Report’s estimate of a $100 Million to $200 Million credit to a $1.3 Billion cost.
Moreover the EDCs assert that the Report does not sufficiently analyze the risk imposed on ratepayers of relying on a speculative projection of capacity prices—exactly the risk that developers claim investors are unwilling to take. The EDCs further argue that the Report fails to explain or support its analysis of energy market impacts, and ignores the fact that these supposed benefits are as susceptible to possible changes in PJM’s mitigation rules as are the capacity market impacts that the Agent “decided to exclude.”

The EDCs believe that the environmental benefits of the recommended portfolio are overstated. They also state the report does not consider the long-term harmful impacts to competitive markets.

The EDCs noted that the Agent correctly decided to reject requests by some generators to modify the final proposed form of SOCA after the bidding occurred. This rejection was necessary because such a change would undermine the competitiveness and credibility of the LCAPP bidding process. If the Board were to change the form of SOCA and to select generators who refused to rely on the form of SOCA that the Agent required all other participants and potential participants to rely on, then it would undermine the entire LCAPP process. At a minimum, the Board would have to conduct an entirely new bid process.

According to the EDCs, while it would be inappropriate for the Board to change the form of SOCA after the parties submitted their bids, the form of SOCA contains some terms that highlight the risks to ratepayers that the Report failed to evaluate in calculating net benefits. First, the form of SOCA does not provide that the SOCA will terminate if a generator fails to clear in any RPM auction during the term of the SOCA. The EDCs previously explained that this departure from the statute undermines ratepayers’ ability to receive the full “net value” of a SOCA, imposes financial costs on ratepayers, and allocates additional risk to ratepayers. The EDCs believe that the form of SOCA does not provide for adequate credit and security requirements. According to the EDCs, such requirements are necessary to protect ratepayers from the risks that the Agent has failed to properly evaluate.

The EDCs continue to encourage the Board to consider whether a suspension of the schedule is appropriate. Such a suspension is fully authorized by the statute and in the discretion of the Board, without any requirement to undergo a standard legal evaluation that would normally accompany a request for a stay. Such a pause would allow the Board to evaluate the outcome of the stakeholder process before burdening New Jersey ratepayers with these significant costs.

Exelon:

Exelon continues to assert the LCAPP Law is unconstitutional and that the proceeding be stayed.

Exelon believes that the Agent’s Report provides no specific information about the individual rankings or weighting of any of the LCAPP criteria. According to Exelon, it appears that the applicants, bidders and the public-at-large will never know how the Agent reached its recommendations. Given the pending cases at FERC and U.S.
District Court, neither the Board nor its Agent can accurately quantify what benefits, if any, will accrue to the State.

According to Exelon, the public interests of New Jersey customers are not served by subjecting them to the costs and risks of the LCAPP with nothing more than the speculative hope that overall energy prices might decline. If the BPU is confident in the Agent’s forecast of capacity prices in the $300-$400 range for the next 15 years, Exelon posits that the BPU should consider a proceeding with the EDCs to immediately enter into as many capacity agreements as possible.

Exelon believes that the Agent should have considered 12, 816MW of new additions in coal, bio-mass, hydro, nuclear, oil and solar and an additional 2700 MW of wind. Furthermore, according to Exelon, the two year grace period for clearing the PJM auction contravenes the Act.

Exelon believes that the Agent employed an overly circumscribed interpretation of the term "eligible generator" and summarily eliminated any applicant that proposed a project involving the expansion of an existing facility, including uprates to existing nuclear units.

West Deptford Township:

According to West Deptford Township, LS Power has purchased 302 acres of land for $14M which property is designated as a Redevelopment Zone and the Township is to receive $107M in PILOT payments over 30 years. The land has sat fallow for a long time with minimal tax receipts for the Township. The Township has invested heavily in working on this project, not to just develop property, but to do so in a way that will provide extraordinary benefits to its residents.

The process by which the Agent has justified refusing to even evaluate the merits, the extremely short Comment Period, and the haste with which the process appears to be moving all suggest that critical mistakes are about to be made. The Township requests that more time be provided for consideration and the Agent’s recommendations be rejected.

Upon review of the comments received, no new information was submitted by any interested party that the necessitated the LCAPP Agent to re-issue its March 21, 2011 Report. Based upon a review of the comments received, the Agent did not modify its recommendation to the Board.

**DISCUSSION AND FINDING**

The Board **HEREBY FINDS** that the LCAPP process was open and transparent, contrary to the assertions of several of the commentators. Notwithstanding the legislatively-mandated timeline to conclude the LCAPP proceeding in sixty (60) days, the LCAPP Agent, Board Staff and Counsel endeavored to solicit public input throughout the proceeding. For instance, interested parties were given the opportunity to comment on two draft versions of the SOCA before the Agent published its final proposed form of SOCA. This opportunity for public input was not a criterion in the legislation; however, the Board sought the comments of all parties, the Agent,
Board Staff in order to assist in promulgating a SOCA that is fair and reasonable and comports with the LCAPP Law.

Although the Agent’s evaluation criteria and underlying analysis were questioned by certain commentators, the LCAPP Agent’s analysis and resulting Report was thorough, rigorous, and in accord with standards of professional excellence. The LCAPP Agent’s analysis was based on a comprehensive and substantial quantitative as well as qualitative analysis. In its evaluation, the LCAPP Agent relied upon various proprietary-licensed market simulation and price forecasting models as well as the Agent’s own in-house proprietary financial models. Furthermore, the LCAPP Agent worked closely with Board Staff and Counsel, as well as New Jersey Department of Environmental Protection throughout the proceeding in order to seek input relating to issues of specific relevance to New Jersey. The Board further notes that the LCAPP Agent has extensive expertise in developing, designing, implementing, administering and monitoring wholesale power procurements. The Board believes that the Agent’s experience and work in other jurisdictions on similar issues as those before the Board in the instant matter, and the scope and detail of the Agent’s Report, that the Board has been provided with sufficient information upon which to make an informed decision.

Based upon the Board’s review of the LCAPP Agent’s report, the public comments and the LCAPP Agent’s presentation to the Board at the March 29, 2011 Agenda Meeting, the Board HEREBY ACCEPTS the Agent’s recommendations as set forth in the Agent’s report dated March 21, 2011, and HEREBY AWARDS SOCAs to the following qualified generators: Hess Newark Energy Project, NRG Old Bridge Clean Energy Center, and CPV Woodbridge Energy Center.

CONFIDENTIAL TREATMENT OF SOCA BID PRICE

Several generators raised concerns over the public release of their respective SOCA price bids. The generators believe that public disclosure of their respective SOCA bid prices may provide an undue competitive advantage to other generators. Furthermore, the generators also believe that public disclosure of their respective SOCA bid price may impact bidding behavior in the relevant PJM BRAs. Based upon these concerns, the Board agrees with the generators that public disclosure of their respective SOCA bid prices may provide an undue advantage to their competitors, and may have the potential to affect bidding behavior in the relevant PJM BRAs. Therefore, the Board HEREBY ORDERS that any of the SOCA bid prices submitted will not be publicly disclosed and will be remain confidential for a limited period of time. Upon a generator submitting a bid and participating in the respective PJM BRA as set forth in its SOCA, the Board HEREBY ORDERS that the SOCA bid price for that generator will be made publicly available and the SOCA bid price will no longer be confidential.

22 The LCAPP Agent is currently advising the Maryland Public Service Commission on matters related to the formulation of a Request For Proposals for new capacity resources. The LCAPP Agent also served as the “prosecutorial arm” of the Connecticut Department of Public Utility Control in Connecticut’s peaking generation procurement process. The LCAPP Agent also currently serves as procurement administrator for capacity, energy renewable energy credits, and long-term renewable energy contracts on behalf of the Illinois Power Agency as well as the administering long-term power contracts for the New York Power Authority and the Long Island Power Authority. It should be noted that many of the interested parties herein should be quite familiar with the LCAPP Agent’s underlying methodology as many of the interested parties in the LCAPP proceeding were participants in one or more of the other states’ proceedings.
COST AND RATE RECOVERY ISSUES

N.J.S.A. 48:3-98.3 (d) provides that: “[f]he board shall order the full recovery of all costs associated with the electric public utilities' resulting SOCAs, and the costs of the agent retained pursuant to subsection b. of this section, from ratepayers through a non-bypassable, irrevocable charge.”

In the February 10 Order, the Board ordered the EDCs to defer any and all reasonably and prudently incurred costs associated with retention of and work performed by the agent retained by the EDCs to assist the Board, for prospective recovery in each of the respective EDC’s next electric distribution base rate proceedings. The Board further ordered the EDCs to maintain all invoices for work performed by said agent as well as records associated with any and all amounts paid to said agent, for the Board's review and consideration, should the EDCs seek recovery of the respective EDC’s portion of the agents' costs. February 10 Order at 7.

On February 24, 2011, the four EDCs collectively filed a Motion For Reconsideration of the February 10 Order pertaining to the recovery of costs incurred by the EDCs in implementing the LCAPP as well as the recovery of the Agent’s costs. The EDCs requested the ability to recover all of the costs they incur associated with the LCAPP through an irrevocable, non-bypassable charge now, and not in their next respective base rate cases.

On March 4, 2011, Rate Counsel filed a response to the EDCs’ Motion For Reconsideration. Rate Counsel opposes the EDCs’ request and supports the recovery of the EDCs’ costs in the context of their next respective base rate cases where such costs would be subject to full prudency review. On March 11, 2011, the EDCs collectively filed an answer to Rate Counsel’s response denying that they were claiming that costs were not subject to a prudency review, but reiterating that recovery through a clause mechanism comports with the LCAPP Law.

As cited above, the LCAPP Law allows the utilities to recover all costs “associated with the electric public utilities' resulting SOCAs, and the costs of the agent retained pursuant to subsection b. of this section, from ratepayers through a non-bypassable, irrevocable charge.” Based upon this provision, the Board is persuaded that the EDCs should not have to wait until final resolution of their next distribution base rate proceedings to recover these costs.

Therefore, based upon the Board’s review of the Motion For Reconsideration and the responses and answers filed, the Board HEREBY MODIFIES its February 10 Order regarding the recovery of costs incurred by the EDCs. This modification is solely limited to the issue of rate recovery by the EDCs of direct costs incurred by the EDCs in implementing the LCAPP as well as the recovery of the LCAPP Agent’s costs. The Board HEREBY AUTHORIZES the EDCs to include in their SOCA Rate Recovery Mechanisms, all reasonably and prudently incurred direct costs associated with the EDCs’ resulting SOCAs, and the costs of the agent, after notice, the opportunity for comment and public hearing, subject to review and approval by the Board. These costs shall be deferred for recovery until the EDCs' prospective SOCA Rate Recovery Mechanism filings when the EDCs seek authority to implement the SOCA rate. This deferred accounting treatment shall include carrying costs at a rate of interest based on two year Treasury notes plus

---

23 Based upon the Agent's Report and Recommendations, a rate would not be established by the Board until on or after June 1, 2015, the first Delivery Year that payments to or from the generators would be triggered under the SOCA.
60 basis points. In the alternative, the Board HEREBY AUTHORIZES the EDCs to request recovery of all reasonably and prudently incurred direct costs associated with the EDCs’ resulting SOCAs, and the costs of the agent, in a distribution base rate proceeding filed with the Board.

Pursuant to the February 10 Order, on March 1, 2011, the EDCs collectively submitted a proposed method to provide selected eligible generators with the requisite payments from the EDCs for the difference between the SOCP and the Resource Clearing Price ("RCP") multiplied by the SOCA capacity in the event the SOCP is greater than the RCP for any applicable delivery year, and to provide the EDCs with refunds from the selected eligible generators for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the RCP is greater than the SOCP for any applicable delivery year, hereinafter referred to as the SOCA rate recovery mechanism.

On March 1, 2011, Gerdau Ameristeel Corporation ("Gerdau"), filed comments regarding the EDCs’ proposed SOCA rate recovery mechanism. Gerdau requested that the non-bypassable LCAPP charge be assessed to ratepayers on the basis of customers’ Peak Load Contributions ("PLC"), which, according to Gerdau, is the basis for assessment of other capacity-related charges.\(^{24}\) Gerdau is authorized to represent that the New Jersey Large Energy Users Coalition, of which Gerdau is an active member, supports the recommendation and requests that any LCAPP non-bypassable charges be assessed on the basis of customers' PLCs.

On March 14, 2011, Rate Counsel submitted comments regarding the EDCs’ SOCA rate recovery mechanism. Rate Counsel proposed that the payments/recoveries from eligible generators be handled in a similar fashion to other Board approved charges, that is, through a per kWh rate that will be trued-up and re-set annually.

On March 18, 2011, the EDCs filed reply comments reiterating their support for the proposal made on March 1, 2011.

On March 24, 2011, Rate Counsel filed comments replying to Gerdau’s request that the Board base payments to be made under the LCAPP legislation on the basis of PLC. Rate Counsel opposes that suggestion as ignoring that the LCAPP payment is a financial hedge, and not a contract for capacity, and that the SOCA is intended to provide benefits in addition to those related to capacity including environmental and other economic benefits, including lower energy prices which will certainly benefit high load factor and high energy use customers. Rate Counsel also addressed the propriety of the Board's previous ruling that LCAPP costs be deferred for recovery in the EDCs' next base rate cases.

Based upon the Board’s review of the EDCs’ proposed SOCA Rate Recovery Mechanism and the comments received, the Board HEREBY REJECTS the EDCs’ SOCA rate recovery mechanism, HEREBY REJECTS Gerdau’s request that the non-bypassable LCAPP charge be assessed to ratepayers on the basis of customers' Peak Load Contributions, and HEREBY ACCEPTS the Rate Counsel proposed rate recovery mechanism. The Board agrees with Rate Counsel’s rationale that Rate Counsel’s proposed SOCA rate recovery mechanism has several advantages over the SOCA rate recovery mechanism proposed by the EDCs. Among those advantages are ease of administration, more transparency and openness to review. Therefore, the Board HEREBY ORDERS the EDCs, individually, to file with the Board, at such time when

\(^{24}\) Gerdau Comments at 2.
payments to or recoveries from the selected generators are triggered pursuant to the SOCA, a SOCA rate recovery mechanism as set forth herein. Specifically, each EDC’s SOCA rate will be recovered or refunded, through a per kWh rate that will be trued-up and re-set annually. For each Delivery Year\textsuperscript{25}, the EDC rate will be filed with the Board by March 1 of the prior Delivery Year with an effective date of June 1. The rate will be based on the Transaction Amounts\textsuperscript{26}, calculated by each EDC that will be provided to the eligible generators at the beginning of each Delivery Year pursuant to the executed SOCA. Interest will be two-way, calculated monthly on a net of tax basis, using the average monthly balance and using an interest rate based on two year Treasury notes plus 60 basis points. Interest will be accrued separately but rolled into the under/over recovered balance when the next Delivery Year’s rate is set. Also, for each year after the first Delivery Year, there will be a true-up filing with the Board which must be filed by August 1 of the subsequent Delivery Year.

EXECUTION OF THE SOCAs

The LCAPP Law requires eligible generators, approved by the Board, to enter into a SOCA with each of the State’s four EDCs provided that each EDC shall pay or receive refunds pursuant to an annually calculated load-ratio share of the capacity of the SOCA based upon each EDC’s annual forecasted peak demand as determined by PJM.\textsuperscript{27} The resulting SOCA shall bind the EDCs to the Board approved SOCAs with selected eligible generators for the term of the SOCA; the selected eligible generators with executed SOCAs shall offer the capacity, electricity, and ancillary services into the PJM wholesale markets as required by the PJM market rules; and that selected eligible generators with executed SOCAs shall participate in and clear the annual base residual auction conducted by the PJM as part of its reliability pricing model for each delivery year of the entire term of the Agreement.

Pursuant to the LCAPP law, the Board shall award the SOCA(s) within thirty (30) days after the Board’s approval of the form of the SOCA (i.e. by April 28, 2011). The Board \textbf{HEREBY ORDERS} each of the State’s four (4) EDCs, namely PSE&G, JCP&L, Rockland and ACE, to individually execute the SOCAs, as approved by the Board herein, with each of the qualified generators as recommended in the Agent’s reissued report, namely the Hess Newark Energy Project, NRG Old Bridge Clean Energy Center, and CPV Woodbridge Energy Center. The EDCs are \textbf{HEREBY ORDERED} to file with the Board, within ten (10) business days of the date of this Order, executed SOCAs for the Board’s consideration. The EDCs shall submit a confidential executed SOCA that includes the respective generator’s SOCA bid price and a public, redacted executed SOCA that does not disclose the respective generator’s SOCA bid price.

\textsuperscript{25} Delivery Year is defined in the SOCA as “each 12-month period from June 1st through May 31st numbered according to the calendar year in which it ends beginning on the Commencement Date and ending on the Conclusion Date.

\textsuperscript{26} The calculation of the Transaction Amounts is detailed in Section 2.2 of the SOCA.

\textsuperscript{27} N.J.S.A. 48:3-98.3 (c )(9).
On February 18, 2011, and March 3, 2011, Motions To Stay the instant proceeding were filed on behalf of certain electric generators and the State's four EDCs, respectively, which were opposed by Rate Counsel and Board Staff. On March 21, 2011, President Solomon, as the Presiding Officer, issued an Order denying the indefinite stay requested by the Movants. The Board HEREBY RATIFIES President Solomon's Order for the reasons stated in his Order.

DATED: 3/29/11

LEE A. SOLOMON
PRESIDENT

JEANNE M. FOX
COMMISSIONER

JOSEPH L. FIORDALISO
COMMISSIONER

NICHOLAS ASSELTA
COMMISSIONER

ATTEST:

KRISTI IZZO
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities

KRISTI IZZO
LONG-TERM CAPACITY AGREEMENT PILOT PROGRAM (LCAPP)
BPU DOCKET NO.: EO110100026

SERVICE LIST

Levitan & Associates, Inc.
100 Summer Street
Suite 3200
Boston, MA 02110
PHONE: (617) 531-2818
FAX: (617) 531-2826
Agent@nj-lcapp.com

Caroline Vachier, DAG,
Section Chief
Division of Law
124 Halsey Street
P.O. Box 45029
Newark, NJ 07101
Caroline.vachier@dol.lps.state.nj.us

Mark Beyer, Chief Economist
Board of Public Utilities
44 So. Clinton Street
Trenton, NJ 08625
mark.beyer@bpu.state.nj.us

Anne M. Shatto, DAG
Division of Law
124 Halsey Street
P.O. Box 45029
Newark, NJ 07101
Anne.shatto@dol.lps.state.nj.us

Andrew K. Dembia
Board of Public Utilities
44 So. Clinton Street
Trenton, NJ 08625
Andrew.dembia@bpu.state.nj.us

Stefanie A. Brand, Director
Division of Rate Counsel
31 Clinton Street – 11th floor
P.O. Box 46005
Newark, NJ 07101
Phone: (973) 648-2690
Fax: (973) 624-1047
Sbrand@rpa.state.nj.us

Kristi Izzo, Secretary
Board of Public Utilities
Two Gateway Center, Suite 801
Newark, NJ 07102
Phone: (973) 648-3426
Fax: (973) 648-2409
Kristi.izzo@bpu.state.nj.us

Paul Flanagan, Litigation Manager
Division of Rate Counsel
31 Clinton Street – 11th floor
P.O. Box 46005
Newark, NJ 07101
Phone: (973) 648-2690
Fax: (973) 642-1047
Pflanagan@rpa.state.nj.us

Jerome May, Director
Board of Public Utilities
Division of Energy
Two Gateway Center, Suite 801
Newark, NJ 07102
Phone: (973) 648-4950
Fax: (973) 648-7420
Jerome.may@bpu.state.nj.us

Lisa Gurkas
Division of Rate Counsel
31 Clinton Street – 11th floor
P.O. Box 46005
Newark, NJ 07102
Phone: (973) 648-2690
lgurkas@rpa.state.nj.us

Frank Perrotti
Board of Public Utilities
Division of Energy
44 So. Clinton Street
Trenton, NJ 08625
Frank.perrotti@bpu.state.nj.us

Ami Morita
Division of Rate Counsel
31 Clinton Street – 11th floor
P.O. Box 46005
Newark, NJ 07102
Amorita@rpa.state.nj.us

Kenneth Sheehan, Chief Counsel
Board of Public Utilities
44 So. Clinton Street
Trenton, NJ 08625
Kenneth.sheehan@bpu.state.nj.us

Diane Schulze, Esq.
Division of Rate Counsel
31 Clinton Street – 11th floor
P.O. Box 46005
Newark, NJ 07101
Phone: (973) 648-2690
Fax: (973) 648-2193
dschulze@rpa.state.nj.us

Babette Tenzer, DAG
Division of Law
124 Halsey Street
P.O. Box 45029
Newark, NJ 07101
Babette.Tenzer@dol.lps.state.nj.us
Gloria Godson  
Atlantic City Electric Co  
401 Eagle Run Road  
Newark, DE 19702  
Gloria.godson@pepcoholdings.com

Philip J. Passanante, Assistant General Counsel  
Atlantic City Electric Co. – 89KS42  
800 King Street – 5th Floor  
P.O. Box 231  
Wilmington, DE 19899-0231  
Phone: (302) 429-3105  
Fax: (302) 429-3801  
Philip.passanante@pepcoholdings.com

Roger E. Pederson, Manager NJ Regulatory Affairs  
Atlantic City Electric Co. – 63ML38  
5100 Harding Highway  
Mays Landing, NJ 08330  
Phone: (609) 625-5820  
Fax: (609) 625-5838  
Roger.pedersen@pepcoholdings.com

Robert Reuter  
Atlantic City Electric Co.  
701 9th Street, NW  
Washington, DC 20001  
Phone: (202) 331-6511  
rreuter@pepco.com

Margaret Comes, Sr. Staff Attorney  
Consolidated Edison Company of NY  
Law Dept. – Room 1815S  
4 Irving Place  
New York, NY 10003  
Phone: (212) 460-3013  
Fax: (212) 677-5850  
comesm@coned.com

Julie L. Friedberg, Esq.  
General Counsel – Northeast Region  
NRG Energy, Inc.  
211 Carnegie Center  
Princeton, New Jersey 08540  
Julie.friedberg@nrgeenergy.com

Kevin Connelly  
First Energy  
300 Madison Avenue  
Morristown, NJ 07960  
Phone: (973) 401-8708  
Fax: (877) 432-9652  
Kconnelly@firstenergycorp.com

Marc B. Lasky  
Morgan, Lewis & Bockius, LLP  
89 Headquarters Plaza North  
Suite 1435  
Morristown, NJ 07960  
Mlasky@morganlewis.com

Larry Sweeney  
First Energy  
300 Madison Avenue  
P.O. Box 1911  
Morristown, NJ 07962-1911  
Phone: (973) 401-8697  
Fax: (973) 644-4157  
lsweeney@firstenergycorp.com

John L. Carley  
Consolidated Edison Co. of NY  
Law Dept. – Room 1815S  
4 Irving Place  
New York, NY 10003  
carleyj@coned.com

Kenneth Carretta, General Regular Markets Counsel  
PSE&G Services Corporation  
80 Park Plaza – T-05, T-05  
Newark, NJ 07102  
Phone: (973) 430-6462  
Fax: (973) 430-5983  
Kenneth.carretta@pseg.com

Gregory Eisenstark  
Associate General Regulatory Co.  
PSE&G Services Corporation  
80 Park Plaza – T-05  
Newark, NJ 07102  
Phone: (973) 430-5281  
Fax: (973) 430-5983  
Gregory.eisenstark@pseg.com

Connie E. Lembo  
PSE&G Services Corporation  
80 Park Plaza – T-05  
Newark, NJ 07102  
Phone: (973) 430-6273  
Fax: (973) 430-5983  
Connstance.lembo@pseg.com

Tamara L. Linde, VP-Regulatory  
PSE&G Services Corporation  
80 Park Plaza – T-05  
Newark, NJ 07102  
Phone: (973) 430-8058  
Fax: (973) 430-5983  
Tamara.linde@pseg.com

Lawrence S. Lustberg  
Kevin McNulty  
Mara E. Zazzali-Hogan  
Gibbons P.C.  
One Gateway Center  
Newark, New Jersey 07102  
llustberg@gibbonslaw.com  
kmcnulty@gibbonslaw.com  
mzazzali-hogan@gibbonslaw.com
David W. DeBruin  
Jared O. Freedman,  
Jenner Block LLP  
1099 New York Ave, N.W.  
Suite 900  
Washington, DC 20001  
ddebruin@jenner.com  
jfreedman@jenner.com

I. David Rosenstein  
NAEA Ocean Peaking Power, LLC  
123 Energy Way  
Lakewood, NJ 08701

Howard Thompson  
Russo Tumulty Nester Thompson & Kelly, LLP  
240 Cedar Knolls Road  
Cedar Knolls, NJ 07927  
hthompson@russo-tumulty.com

William F. Harrison  
Genova, Burns & Giantomasi  
494 Broad Street  
Newark, N.J. 07102  
wharrison@genovaburns.com

Sarah G. Novosel  
Calpine Corporation  
1401 H Street, N.W.  
Washington, D.C. 20005

Stephen B. Genzer  
Colleen A. Foley  
Saul Ewing LLP  
One Riverfront Plaza, Suite 1520  
Newark, N.J. 07102  
sgenzer@saul.com  
cfoley@saul.com
IN THE MATTER OF THE LONG-TERM CAPACITY AGREEMENT PILOT PROGRAM

ORDER

DOCKET NO. EO11010026

(SERVICE LIST ATTACHED)

BY THE BOARD:

On January 28, 2011, Governor Chris Christie signed into law P.L. 2011, c.9, amending and supplementing P.L. 1999, c. 23, which law establishes a long-term capacity agreement pilot program ("LCAPP") to promote the construction of qualified electric generation facilities, hereinafter referred to as the LCAPP Law.1 Pursuant to the LCAPP Law, on February 10, 2011, the New Jersey Board of Public Utilities ("Board") initiated this proceeding and also approved the retention, as recommended by the electric distribution companies ("EDCs"), of an agent ("LCAPP Agent") to assist the Board in this proceeding.2 On March 29, 2011, the Board approved the recommendations in the LCAPP Agent's report dated March 21, 2011. The Board also approved the form of the Standard Offer Capacity Agreement ("SOCA") as modified for technical corrections, and ordered the EDCs to execute the SOCA with each recommended generator.

BACKGROUND:

Pursuant to the LCAPP Law, the Board was mandated to immediately commence a proceeding to establish an LCAPP.3 The LCAPP seeks offers for financially-settled SOCA with eligible generators.4 The LCAPP Law requires selected eligible generators, with Board approved and

---

1 The provisions of the LCAPP Law have been codified in the following sections of the New Jersey Statutes: N.J.S.A. 48:3-51, 48:3-60.1, 48:3-98.3—98.4.
2 N.J.S.A. 48:3-98.3(b).
3 N.J.S.A. 48:3-98.3(a).
4 "Eligible generator" means a developer of a base load or mid-merit electric power generation facility including, but not limited to, an on-site generation facility that qualifies as a capacity resource under PJM criteria and that commences construction after 1/28/2011. N.J.S.A. 48:3-51.
executed SOCA(s) to participate in and be accepted as a capacity resource in the base residual auction conducted by PJM. The SOCA, as defined in the LCAPP Law, is a financially settled transaction agreement that allows eligible generators to receive payments from or make payments to the EDCs for a defined amount of electric capacity for a term specified by the Board not to exceed fifteen (15) years. Pursuant to the LCAPP Law, these payments are implemented through a fully non-bypassable irrevocable charge.

EXECUTION OF THE SOCA

The LCAPP Law requires eligible generators to enter into a SOCA with each of the State's four EDCs providing that each EDC shall pay or receive refunds pursuant to an annually calculated load-ratio share of the capacity of the SOCA based upon each EDC's annual forecasted peak demand as determined by PJM. The resulting SOCA shall bind the EDCs to the Board approved SOCA with selected eligible generators for the term of the SOCA; the selected eligible generators with executed SOCA shall offer the capacity, energy, and ancillary services into the PJM wholesale markets as required by the PJM market rules; and selected eligible generators with executed SOCA shall participate in and clear the annual base residual auction conducted by the PJM as part of its reliability pricing model for each delivery year of the entire term of their respective Agreements.

N.J.S.A 48:3-98.3 (a) directs the Board to award the SOCA(s) within thirty (30) days after the Board's approval of the form of the SOCA, in this case by April 28, 2011. In its March 29, 2011 Order, the Board ordered each of the State's four (4) EDCs, namely Public Service Electric & Gas Company, Jersey Central Power & Light Company, Rockland Electric Company and Atlantic City Electric Company, to individually execute the SOCA, as approved by the Board, with each of the qualified generators as recommended in the Agent's March 21, 2011 report, namely, the Hess Newark Energy Project, the NRG Old Bridge Clean Energy Center, and the CPV Woodbridge Energy Center.

In compliance with the March 29, 2011 Order, each of the EDCs has executed a SOCA with each qualified generator approved by the Board, and has submitted a confidential executed SOCA that includes the respective generator's SOCA bid price, and a public, redacted executed SOCA that does not disclose the respective generator's SOCA bid price. The SOCA bid prices submitted will not be publicly disclosed at this time, and will be remain confidential for a limited period of time. Upon a generator submitting a bid and participating in the respective PJM Base Residual Auction as set forth in its SOCA, the SOCA bid price for that generator will be made publicly available, and will no longer be treated as confidential information.

5 N.J.S.A. 48:3-98.3(a).
6 N.J.S.A. 48:3-51.
7 N.J.S.A. 48:3-98.3 (c)(9).
8 N.J.S.A. 48:3-98.3 (c) 10—12.
9 Each EDC submitted a similar cover letter with the executed SOCA stating that it executed the SOCA under protest, reserving its rights to various challenges to the LCAPP proceeding and the terms of the SOCA.
Based on its review of the executed SOCAs, and after consideration of the comments of the EDCs, the Board **HEREBY FINDS** that the executed SOCAs comply with the requirements of the March 29 Order, and **HEREBY APPROVES** each of the executed SOCAs.

DATED: 5/4/11

BOARD OF PUBLIC UTILITIES

BY:

LEE A. SOLOMON
PRESIDENT

JEANNE M. FOX
COMMISSIONER

JOSEPH L. FIORDALISO
COMMISSIONER

NICHOLAS ASSELTA
COMMISSIONER

ATTEST:
KRISTI IZZO
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities

KRISTI IZZO
# Long-Term Capacity Agreement Pilot Program (LCAPP)

**BPU Docket No.: EO11010026**

## Service List

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>100 Summer Street</td>
<td>Division of Law</td>
<td>Division of Rate Counsel</td>
</tr>
<tr>
<td>Suite 3200</td>
<td>124 Halsey Street</td>
<td>31 Clinton Street – 11th floor</td>
</tr>
<tr>
<td>Boston, MA 02110</td>
<td>P.O. Box 45029</td>
<td>P.O. Box 46005</td>
</tr>
<tr>
<td>PHONE: (617) 531-2818</td>
<td>Newark, NJ 07101</td>
<td>Newark, NJ 07101</td>
</tr>
<tr>
<td>FAX: (617) 531-2826</td>
<td><a href="mailto:Babette.Tenzer@dol.lps.state.nj.us">Babette.Tenzer@dol.lps.state.nj.us</a></td>
<td>Phone: (973) 648-2690</td>
</tr>
<tr>
<td><a href="mailto:Agent@ni-lcapp.com">Agent@ni-lcapp.com</a></td>
<td></td>
<td>Fax: (973) 648-2193</td>
</tr>
</tbody>
</table>

| Mark Beyer, Chief Economist | Caroline Vachier, DAG, Section Chief | Gloria Godson |
| Board of Public Utilities   | Division of Law     | Atlantic City Electric Co |
| 44 So. Clinton Street       | 124 Halsey Street   | 401 Eagle Run Road     |
| Trenton, NJ 08625           | P.O. Box 45029      | Newark, DE 19702       |
| Mark.Beyer@bpu.state.nj.us  | Newark, NJ 07101    | Gloria.godson@pepcoholdings.com |

| Andrew K. Dembia           | Anne M. Shatto, DAG | Philip J. Passanante, Assistant General Counsel |
| Board of Public Utilities  | Division of Law     | Atlantic City Electric Co. – 89KS42 |
| 44 So. Clinton Street      | 124 Halsey Street   | 800 King Street – 5th floor |
| Trenton, NJ 08625          | P.O. Box 45029      | P.O. Box 231           |
| Andrew.dembia@bpu.state.nj.us | Newark, NJ 07101   | Wilmington, DE 19899-0231 |

| Kristi Izzo, Secretary     | Stefanie A. Brand, Director | Roger E. Pederson, Manager NJ Regulatory Affairs |
| Board of Public Utilities  | Division of Rate Counsel  | Atlantic City Electric Co. – 63ML38 |
| Two Gateway Center, Suite 801 | 31 Clinton Street – 11th floor | 5100 Harding Highway |
| Newark, NJ 07102           | P.O. Box 46005        | Mays Landing, NJ 08330  |
| Phone: (973) 648-3426      | Newark, NJ 07101      | Phone: (609) 625-5820   |
| Fax: (973) 648-2409        | Phone: (973) 648-2690  | Fax: (609) 625-5838     |
| Kristi.izzo@bpu.state.nj.us| Fax: (973) 624-1047    | Roger.pedersen@pepcoholdings.com |

| Jerome May, Director       | Paul Flanagan, Litigation Manager | Robert Reuter |
| Board of Public Utilities  | Division of Rate Counsel  | Atlantic City Electric Co |
| Division of Energy         | 31 Clinton Street – 11th floor | 701 9th Street, NW |
| Two Gateway Center, Suite 801 | P.O. Box 46005        | Washington, DC 20001   |
| Newark, NJ 07102           | Newark, NJ 07101       | Phone: (202) 331-6511   |
| Phone: (973) 648-4950      | Phone: (973) 648-2690   | rreuter@peppco.com      |
| Fax: (973) 648-7420        | Fax: (973) 624-1047     | Margaret Comes, Sr. Staff Attorney |
| Jerome.may@bpu.state.nj.us | Paul.Flanagan@bpu.state.nj.us | Consolidated Edison Company of NY |

| Frank Perrotti            | Lisa Gurkas          | Margaret Comes, Sr. Staff Attorney |
| Board of Public Utilities | Division of Rate Counsel | Law Dept. – Room 1815S |
| Division of Energy        | 31 Clinton Street – 11th floor | 4 Irving Place |
| 44 So. Clinton Street     | P.O. Box 46005       | New York, NY 10003       |
| Trenton, NJ 08625         | Newark, NJ 07102     | Phone: (212) 460-3013    |
| Frank.Perrotti@bpu.state.nj.us | Phone: (973) 648-2690 | Fax: (212) 677-5850     |

| Kenneth Sheehan, Chief Counsel | Lisa.Gurkas@bpu.state.nj.us | Margaret Comes, Sr. Staff Attorney |
| Board of Public Utilities     |                           | Law Dept. – Room 1815S |
| 44 So. Clinton Street         |                           | 4 Irving Place |
| Trenton, NJ 08625             |                           | New York, NY 10003       |
| Kenneth.Sheehan@bpu.state.nj.us |                          | Phone: (212) 460-3013    |

| Ami Morita                   |                           | Margaret Comes, Sr. Staff Attorney |
| Division of Rate Counsel     |                           | Law Dept. – Room 1815S |
| 31 Clinton Street – 11th floor |                          | 4 Irving Place |
| P.O. Box 46005               |                           | New York, NY 10003       |
| Newark, NJ 07102             |                           | Phone: (212) 460-3013    |
| Ami.Morita@bpu.state.nj.us   |                           | Fax: (212) 677-5850     |
Julie L. Friedberg, Esq.  
General Counsel – Northeast Region  
NRG Energy, Inc.  
211 Carnegie Center  
Princeton, New Jersey 08540  
Julie.friedberg@nrgenergy.com

Connie E. Lembo  
PSEG Services Corporation  
80 Park Plaza – T-05  
Newark, NJ 07102  
Phone: (973) 430-6273  
Fax: (973) 430-5983  
Constance.lembo@pseg.com

Stephen B. Genzer  
Colleen A. Foley  
Saul Ewing LLP  
One Riverfront Plaza, Suite 1520  
Newark, N.J. 07102  
sgenzer@saul.com  
cfoley@saul.com

Kevin Connelly  
First Energy  
300 Madison Avenue  
Morristown, NJ 07960  
Phone: (973) 401-8708  
Fax: (877) 432-9652  
kconnelly@firstenergycorp.com

Tamara L. Linde, VP-Regulatory  
PSEG Services Corporation  
80 Park Plaza – T-05  
Newark, NJ 07102  
Phone: (973) 430-8058  
Fax: (973) 430-5983  
Tamara.linde@pseg.com

Thomas P. Thackston  
Associate General Counsel  
Hess Corporation  
1 Hess Plaza  
Woodbridge, NJ 07095  
(732) 750-6856 Office  
TThackston@hess.com

Marc B. Lasky  
Morgan, Lewis & Bockius, LLP  
89 Headquarters Plaza North Suite 1435  
Morristown, NJ 07960  
mlasky@morganlewis.com

Lawrence S. Lustberg  
Kevin McNulty  
Mara E. Zazzali-Hogan  
Gibbons P.C.  
One Gateway Center  
Newark, New Jersey 07102  
llustberg@gibbonslaw.com  
kmcnulty@gibbonslaw.com  
mzazzali-hogan@gibbonslaw.com

John L. Carley  
Consolidated Edison Co. of NY  
Law Dept. – Room 1815S  
4 Irving Place  
New York, NY 10003  
carleyi@coned.com

David W. DeBruin  
Jared O. Freedman,  
Jenner Block LLP  
1099 New York Ave, N.W  
Suite 900  
Washington, DC 20001  
ddebriu@jenner.com  
jfreedman@jenner.com

Kenneth Carretta, General Regular  
Markets Counsel  
PSE&G Services Corporation  
80 Park Plaza – T-05, T-05  
Newark, NJ 07102  
Phone: (973) 430-6462  
Fax: (973) 430-5983  
Kenneth.carretta@pseg.com

I. David Rosenstein  
NAEA Ocean Peaking Power, LLC  
123 Energy Way  
Lakewood, NJ 08701

Gregory Eisenstark  
Associate General Regulatory Co.  
PSEG Services Corporation  
80 Park Plaza – T-05  
Newark, NJ 07102  
Phone: (973) 430-6281  
Fax: (973) 430-5983  
Gregory.eisenstark@pseg.com

Howard Thompson  
Russo Tumulty Nester Thompson & Kelly, LLP  
240 Cedar Knolls Road  
Cedar Knolls, NJ 07927  
hthompson@rusotumulty.com

Sarah G. Novosel  
Calpine Corporation  
1401 H Street, N.W.  
Washington, D.C. 20005
NEW JERSEY’S INITIATIVE TO FOSTER THE DEVELOPMENT OF GENERATION CAPACITY & ADDRESS RELIABILITY ISSUES:

LONG-TERM CAPACITY AGREEMENT PILOT PROGRAM ("LCAPP")

Andrew K. Dembia
Legal Specialist
NJ Board of Public Utilities
LCAPP-MECHANICS

- Law required NJ BPU to conduct a proceeding to solicit & evaluate bids to procure 2,000MWs of new generation capacity;
- LCAPP Agent selected and retained by State’s four electric utilities;
- NJ BPU approved the recommendations of its LCAPP Agent and awarded Standard Offer Capacity Agreements ("SOCAs") to three generators;
- NJ BPU ordered the State’s four electric utilities to execute the SOCA with each of the selected generators;
- Each SOCA is for a fifteen year term;
- Generator does not receive any payments unless it clears the PJM Reliability Pricing Model ("RPM") Base Residual Auction ("BRA");
- SOCA terminates after three failed attempts to clear the BRA.
WHY LCAPP?

- **Reliability**
  - RPM not working in NJ as intended
  - Little new in-state generation being developed
  - Problematic delays in back-bone transmission coming “on-line”

- **Economic**
  - Protect ratepayers from substantial price increases (congestion costs) due to lack of back-bone transmission being placed into service.
RECENT MOPR CHANGES & THE IMPACT ON LCAPP

- FERC’s April 12, 2011 Decision changed the RPM Minimum Offer Price Rules (“MOPR”);
  - One of the MOPR changes was the elimination of the state-sponsored project exemption that would not have subjected state-sponsored projects to MOPR mitigation.
    - New combined cycle gas fired units now must submit a price bid of 90% of Net CONE and not reflect in its bid price any state awarded incentive.
- FERC’s decision directly impacts NJ’s LCAPP as the generators with a SOCA would now be subject to mitigation, and therefore, unlikely to clear the BRA.
- NJ BPU is seeking Rehearing of the FERC’s April 12, 2011 decision.
POST LCAPP

- Events are expected to occur during this decade that will have an impact on the reliability of supply and reliability of the transmission grid in NJ:
  - Delays in back-bone transmission coming on-line;
  - New EPA Clean Air & Clean Water rules which may accelerate the retirement of some generating units;
  - Early retirement of the Oyster Creek nuclear station (619MW) in Ocean County, NJ in 2019;
  - Exports of power out of NJ into NYISO.

- LCAPP Agent noted that New Jersey might benefit from additional capacity beyond the 2,000MWs procured under LCAPP depending on pricing and other conditions.
NJ BPU NEXT STEPS

- NJ BPU has initiated a proceeding to investigate:
  - possible impediments to the development of new capacity in NJ;
  - the competitiveness of the State’s power market;
  - issues concerning the PJM transmission planning and interconnection process; and
  - the possible procurement of additional capacity beyond the 2,000MWs under LCAPP.
NEXT STEPS

- See what action, if any, FERC takes regarding the MOPR rehearing request
  - NJ BPU requested the re-instatement of the MOPR exemption for state-sponsored projects, or, alternatively, grandfather the three LCAPP generators from its April 12, 2011 decision
- Take appropriate legal action, if warranted, based upon the rehearing request
- Proceed with NJ BPU investigation
- Adjust course accordingly
AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is proposing to amend the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. With respect to transmission planning, the proposed rule would (1) provide that local and regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) improve coordination between neighboring transmission planning regions with respect to interregional facilities; and (3) remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer. Neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved tariff or agreement, receive different treatment in a regional transmission
planning process. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. With respect to cost allocation, the proposed rule would establish a closer link between transmission planning processes and cost allocation and would require cost allocation methods for intraregional and interregional transmission facilities to satisfy newly established cost allocation principles.

DATES: Comments are due [insert date that is 60 days after publication in the FEDERAL REGISTER].

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.
FOR FURTHER INFORMATION CONTACT:

Russell Profozich
Federal Energy Regulatory Commission
Office of Energy Policy and Innovation
888 First Street, NE
Washington, DC 20426
(202) 502-6478

John Cohen
Federal Energy Regulatory Commission
Office of the General Counsel
888 First Street, NE
Washington, DC 20426
(202) 502-8705

SUPPLEMENTARY INFORMATION:
TABLE OF CONTENTS

I. Introduction ............................................................................................................................1.

II. Background ...........................................................................................................................5.
   A. Order Nos. 888 and 890 ...................................................................................................5.
   B. Technical Conferences and Notice of Request for Comments on Transmission Planning and Cost Allocation .................................................................12.
   C. Additional Developments since Issuance of Order No. 890 ...........................................24.

III. The Need for Reform ...........................................................................................................31.

   A. Participation in the Regional Planning Process ..............................................................42.
   B. Public Policy Driven Projects ...........................................................................................52.
   C. Opportunities for Undue Discrimination against Nonincumbent Transmission Developers ..................................................................................................................69.
   D. Interregional Coordination ..............................................................................................100.
      1. The Need for Interregional Planning Reforms ...........................................................100.
      2. Proposed Interregional Planning Reforms .................................................................112.

V. Proposed Reforms: Cost Allocation .............................................................................118.
   A. Introduction ......................................................................................................................118.
Appendix A: List of Short Names of Commenters on the Federal Energy Regulator Commission’s Notice of Request for Comments on Transmission Planning Processes under Order No. 890—Docket No. AD09-8-000, October 2009

Appendix B: Pro Forma Open Access Transmission Tariff Attachment K
NOTICE OF PROPOSED RULEMAKING

(Issued June 17, 2010)

I. Introduction

1. In this Notice of Proposed Rulemaking (Proposed Rule), the Federal Energy Regulatory Commission (Commission) is proposing to reform its electric transmission planning and cost allocation requirements for public utility transmission providers. The proposed reforms are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

2. This Proposed Rule builds on Order No. 890,\(^1\) in which the Commission reformed the *pro forma* open access transmission tariff (OATT). Among other changes, Order

No. 890 required each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. Order No. 890 also established nine transmission planning principles, one of which addressed cost allocation for new projects.

3. The Commission acknowledges that significant work has been done in recent years to enhance regional transmission planning processes. The reforms proposed herein seek to build on this progress by improving the effectiveness of regional transmission planning and the efficiency of resulting transmission development. In formulating this proposal, the Commission has sought to balance competing interests and identify a package of reforms that, if implemented, would support the development of transmission facilities identified by the region as necessary to satisfy reliability standards, reduce congestion, and enable compliance with public policy requirements established by state or federal laws or regulations. The Commission recognizes that opinions may differ as to whether the proposal as formulated will best achieve the Commission's goals. The Commission therefore seeks comment on the reforms proposed herein and encourages commenters to identify enhancements to the reforms that could better support the efficient and effective development of transmission facilities.

4. With respect to transmission planning, the reforms proposed in this Proposed Rule would provide that: (1) local and regional transmission planning processes account for

transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) coordination between neighboring transmission planning regions is improved with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that could address transmission needs more efficiently than separate intraregional facilities; and (3) a right of first refusal that is created by a document subject to the Commission’s jurisdiction and that provides an incumbent utility with an undue advantage over nonincumbent transmission project developers is removed from that document. Neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a regional transmission planning process. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. The Commission preliminarily finds that these proposed reforms are needed to protect against unjust and unreasonable rates, terms and conditions and undue discrimination in the provision of Commission-jurisdictional services.

5. With respect to transmission cost allocation, the Commission is proposing to require public utility transmission providers to establish a closer link between cost allocation and regional transmission planning processes in which the beneficiaries of new transmission facilities are identified, as well as to establish principles that cost allocation methods must satisfy. The Commission sees these proposals as steps that would increase
the likelihood that facilities included in regional transmission plans are actually constructed. For example, establishing a closer link between transmission planning and cost allocation processes would diminish the likelihood that a transmission facility would be included in a regional transmission plan, only to later encounter cost allocation disputes that inhibit construction of that facility.

II. Background

A. Order Nos. 888 and 890

6. In Order No. 888, issued in 1996, the Commission found that it was in the economic interest of transmission providers to deny transmission service or to offer transmission service on a basis that is inferior to that which they provide to themselves. Concluding that unduly discriminatory and anticompetitive practices existed in the electric industry and that, absent Commission action, such practices would increase as competitive pressures in the industry grew, the Commission in Order No. 888 and the accompanying pro forma OATT implemented open access to transmission facilities owned, operated, or controlled by a public utility.

---


3 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,682.
7. As part of those reforms, Order No. 888 and the *pro forma* OATT set forth certain minimum requirements for transmission planning. For example, the *pro forma* OATT required a public utility transmission provider to account for the needs of its network customers in its transmission planning activities on the same basis as it provides for its own needs.\(^4\) The *pro forma* OATT also required that new facilities be constructed to meet the service requests of long-term firm point-to-point customers.\(^5\) While Order No. 888-A went on to encourage utilities to engage in joint and regional transmission planning with other utilities and customers, it did not require those actions.\(^6\)

8. In early 2007, the Commission issued Order No. 890 to remedy flaws in the *pro forma* OATT that the Commission identified based on the decade of experience since the issuance of Order No. 888. Among other things, the Commission found that *pro forma* OATT obligations related to transmission planning were insufficient to eliminate opportunities for undue discrimination in the provision of transmission service. The Commission stated that particularly in an era of increasing transmission congestion and the need for significant new transmission investment, it could not rely on the self-interest of transmission providers to expand the grid in a not unduly discriminatory manner. Among other shortcomings in the *pro forma* OATT, the Commission pointed to the lack of clear criteria regarding the transmission provider’s planning obligation; the absence of a requirement that the overall transmission planning process be open to customers,

\(^4\) See Section 28.2 of the *pro forma* OATT.

\(^5\) See Sections 13.5, 15.4, & 27 of the *pro forma* OATT.

\(^6\) Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,311.
competitors, and state commissions; and the absence of a requirement that key
assumptions and data underlying transmission plans be made available to customers.

9. In light of these findings, one of the primary goals of the reforms undertaken in
Order No. 890 was to address the lack of specificity regarding how customers and other
stakeholders should be treated in the transmission planning process. To remedy the
potential for undue discrimination in transmission planning activities, the Commission
required each public utility transmission provider to develop a transmission planning
process that satisfies nine principles and to clearly describe that process in a new
attachment to its OATT (Attachment K). The Order No. 890 transmission planning
principles are: (1) coordination; (2) openness; (3) transparency; (4) information
exchange; (5) comparability; (6) dispute resolution; (7) regional participation;
(8) economic planning studies; and (9) cost allocation for new projects.\(^7\)

10. The transmission planning reforms adopted in Order No. 890 apply to all public
utility transmission providers, including Commission-approved regional transmission
organizations (RTOs) and independent system operators (ISOs). The Commission also
stated that it expected all non-public utility transmission providers to participate in the
planning processes required by Order No. 890. The Commission noted that reciprocity
dictates that non-public utility transmission providers that take advantage of open access
due to improved planning should be subject to the same requirements as jurisdictional

\(^7\) Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 418-601.
transmission providers.\textsuperscript{8} The Commission stated that a coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. However, the Commission did not invoke its authority under FPA section 211A, which allows the Commission to require an unregulated transmitting utility (i.e., a non-public utility transmission provider) to provide transmission services on a comparable and not unduly discriminatory or preferential basis.\textsuperscript{9} The Commission instead stated that if it found on the appropriate record that non-public utility transmission providers are not participating in the planning processes required by Order No. 890, then the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

11. On December 7, 2007, pursuant to Order No. 890, most public utility transmission providers and several non-public utility transmission providers submitted compliance filings that describe their proposed transmission planning processes.\textsuperscript{10} The Commission addressed these filings in a series of orders that were issued throughout 2008. Generally, the Commission accepted the compliance filings to be effective December 7, 2007, subject to further compliance filings as necessary for the proposed transmission planning

\textsuperscript{8} \textit{Id.} P 441.

\textsuperscript{9} FPA section 211A(b) provides, in pertinent part, that “the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services – (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.” 16 U.S.C. 824j (2006).

\textsuperscript{10} A small number of transmission providers were granted extensions.
processes to satisfy the nine transmission planning principles. The Commission issued additional orders on Order No. 890 transmission planning compliance filings in the spring and summer of 2009.

12. As a result of these compliance filings, RTOs and ISOs have enhanced their regional transmission planning processes, making them more open, transparent, and inclusive. Regions of the country outside of RTO and ISO regions have also made significant strides with respect to transmission planning by working together to enhance existing, or create new, regional transmission planning processes.\textsuperscript{11} These improvements to transmission planning processes have given customers and other stakeholders the opportunity to participate in the identification of regional needs and corresponding solutions, thereby facilitating the development of more efficient and effective transmission expansion plans.

**B. Technical Conferences and Notice of Request for Comments on Transmission Planning and Cost Allocation**

13. In several of the above-noted orders issued in 2008 and early 2009 on filings submitted to comply with the Order No. 890 transmission planning requirements, the Commission stated that it would continue to monitor implementation of these

\textsuperscript{11} The regional transmission planning processes that public utility transmission providers in regions outside of RTOs and ISOs have relied on to comply with certain requirements of Order No. 890 are the North Carolina Transmission Planning Collaborative, Southeast Inter-Regional Participation Process, SERC Reliability Corporation, ReliabilityFirst Corporation, Mid-Continent Area Power Pool, Florida Reliability Coordination Council, WestConnect, ColumbiaGrid, and Northern Tier Transmission Group.
transmission planning processes. The Commission also announced its intention to convene regional technical conferences in 2009.

14. Consistent with the Commission’s announcement, Commission staff in September 2009 convened three regional technical conferences in Philadelphia, Atlanta, and Phoenix, respectively. The focus of the technical conferences was to: (1) determine the progress and benefits realized by each transmission provider’s transmission planning process, obtain customer and other stakeholder input, and discuss any areas that may need improvement; (2) examine whether existing transmission planning processes adequately consider needs and solutions on a regional or interconnection-wide basis to ensure adequate and reliable supplies at just and reasonable rates; and (3) explore whether existing processes are sufficient to meet emerging challenges to the transmission system, such as the development of interregional transmission facilities and the integration of large amounts of location-constrained generation. Issues discussed at the technical conferences included the effectiveness of the current transmission planning processes, the development of regional and interregional transmission plans, and the effectiveness of existing cost allocation methods used by transmission providers and alternatives to those methods.

15. Following these technical conferences, the Commission in October 2009 issued a Notice of Request for Comments. 12 The October 2009 Notice presented numerous

---

questions with respect to enhancing regional transmission planning processes and allocating the cost of transmission.

16. In response to the October 2009 Notice, the Commission received 107 initial comments and 45 reply comments. Many of these comments are discussed in greater detail later in this Proposed Rule, in the context of the Commission’s proposals on specific issues.

17. In general, some commenters oppose additional Commission action at this time with respect to transmission planning. Among these commenters, some argue that existing transmission planning processes are adequate to achieve the Commission’s stated goals. Some of these commenters highlight work already underway in their own transmission planning regions, arguing that no Commission action is needed at least in those regions. Other commenters argue that existing processes are new or are being revised and should be given time to mature before additional changes are proposed. Many of these commenters state that if the Commission chooses to act, it should do so in a manner that does not disrupt existing transmission planning processes. Some commenters that oppose Commission action on transmission planning at this time state that it is important to maintain what they describe as a “bottom-up” approach to transmission planning, in which regional transmission planning is based on transmission

____________________

13 See Appendix A for a list of the commenters and their abbreviated names.

14 E.g., Dominion, Large Public Power Council, Midwest ISO, New York PSC, Northern Tier Transmission Group, and WECC.
planning conducted by the individual transmission-owning utilities in a transmission planning region.\(^{15}\)

18. Many other commenters support additional Commission action on transmission planning at this time.\(^{16}\) These commenters offer a wide range of views on why and how the planning process should be improved. Although these commenters express diverse views, there appears to be a consensus among those supporting action that the Commission should—at a minimum—provide guidance about planning for large, interregional transmission projects.

19. Many commenters that support Commission action on transmission planning raise issues related to the procedural characteristics or geographic scope of existing transmission planning processes. Some commenters contend that the Order No. 890 transmission planning principles should be extended to support interregional coordination, while others argue that additional planning principles are necessary to ensure the effectiveness of transmission planning processes. Some commenters suggest that the type of “bottom-up” transmission planning described above is insufficient,\(^{17}\) and other commenters advocate changes such as establishing a regional or interconnection-wide planning coordinator.\(^{18}\) A few commenters suggest that the Commission add to the

---

\(^{15}\) E.g., Ohio Commission, PPL, Southern Companies, and WECC.


\(^{17}\) E.g., Calvin Daniels (commenting as an individual).

\(^{18}\) E.g., AEP.
OATT a *pro forma* seams agreement that includes joint collaborative planning and cost allocation across planning regions.\(^{19}\) Still other commenters support changes to transmission planning processes, but caution against adopting a one-size-fits-all or an interconnectionwide approach.\(^{20}\)

20. Other commenters that support Commission action on transmission planning argue that some existing transmission planning processes provide an incumbent transmission owner with an unfair advantage over merchant and independent transmission project developers, such as by providing an incumbent transmission owner with a right of first refusal\(^{21}\) to construct a transmission facility that is included in a regional transmission plan and meets certain other criteria.\(^{22}\) These commenters argue that such practices discourage other, merchant and independent transmission developers\(^{23}\) participation in the transmission planning process and present a significant barrier to transmission

\(^{19}\) *E.g.*, Midwest ISO Transmission Owners, National Rural Electric Coops, and SPP.

\(^{20}\) *E.g.*, Pacific Gas and Electric and Transmission Agency of Northern California.

\(^{21}\) A right of first refusal is defined, for the purposes of this proposed rulemaking, as the right of an incumbent transmission owner to construct, own, and propose cost recovery for any new transmission project that is: (1) located within its service territory; and (2) approved for inclusion in a transmission plan developed through the Order No. 890 planning process.

\(^{22}\) *E.g.*, AWEA, EPSA, LS Power, and Transmission Dependent Utility Systems.

\(^{23}\) Merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates. For purposes of this proposed rulemaking, an incumbent transmission developer is an entity that develops a project within its own service territory. We note that a transmission owner that proposes a project outside of its own service territory is not considered an incumbent for purposes of that project.
investment. Other commenters state that projects proposed by merchant and independent transmission project developers need to be included fully in regional transmission planning processes on the same basis as other projects.\(^{24}\)

21. Still other commenters that support Commission action on transmission planning express concern that current transmission planning processes do not adequately assess all of the potential benefits associated with transmission project proposals.\(^{25}\) Some of these commenters state that more attention needs to be devoted to analyzing the benefits associated with economic-based projects and incorporating such projects into regional transmission plans.\(^{26}\) PJM states that generic planning principles are needed to deal with the various social, environmental and economic impacts of regional transmission projects. In addition, several commenters recommend that the Commission incorporate state and federal public policy objectives into the transmission planning process,\(^{27}\) noting, for example, that doing so could facilitate cost-effective achievement of those objectives.

\(^{24}\) *E.g.*, Allegheny Companies, AEP, CAilifornians for Renewable Energy, Delaware Municipal and Southwestern Electric, E.ON Climate & Renewables North America, Great River Energy, Sun Flower and Mid-Kansas, National Nuclear Security Administration Service Center, Organization of MISO States, and Transmission Agency of Northern California.


\(^{26}\) *E.g.*, MidAmerican and Old Dominion.

Commenters also recommend that the Commission provide for flexibility so that each transmission planning region could determine which resources it would use to fulfill these public policy objectives.\(^{28}\)

22. The Commission’s questions in the October 2009 Notice with respect to allocating the cost of transmission also drew wide-ranging responses. For example, some commenters express concern that the lack of a link between transmission planning and cost allocation procedures may unnecessarily block or delay needed projects.\(^{29}\) Other commenters support establishing a generic cost allocation method as a backstop that would apply when parties or transmission planning regions cannot agree on a cost allocation method.\(^{30}\)

23. Some commenters indicate that the Commission should provide more detailed guidelines or principles for allocating the costs of new transmission facilities.\(^{31}\) These commenters generally agree that those who share in the benefits of transmission facilities should be responsible for their costs. However, there is not a consensus on how this principle should be implemented, what benefits should be considered for purposes of cost allocation, or how to determine who is a beneficiary.

\(^{28}\) *E.g.*, Consolidated Edison, *et al.*

\(^{29}\) *E.g.*, ITC Holdings, AEP, American Transmission, Green Energy Express, and WIRES.

\(^{30}\) *E.g.*, American Transmission; National Grid; and NEPOOL Participants.

24. Some commenters urge the Commission to avoid rushing to a one-size-fits-all approach to determining beneficiaries of transmission projects, due to the varying nature of projects and benefits.\textsuperscript{32} Others express the view that it is difficult to quantify certain benefits that they consider relevant, such as carbon emission reduction, integration of renewable generation, or the most efficient use of existing rights-of-way.\textsuperscript{33} Other commenters suggest that there are ways to factor difficult to quantify benefits into the planning process such that they are adequately considered.\textsuperscript{34}

C. \textbf{Additional Developments Since Issuance of Order No. 890}

25. Other developments with important implications for transmission planning have occurred amid the above-noted Order No. 890 compliance efforts on transmission planning and as the Commission gathered information through the technical conferences and the October 2009 Notice discussed above.

26. For example, in February 2009, Congress enacted the American Recovery and Reinvestment Act (ARRA), which provided $80 million for the U.S. Department of Energy (DOE), in coordination with the Commission, to support the development of interconnection-based transmission plans for the Eastern, Western, and Texas interconnections. In seeking applications for use of those funds, DOE described the

\textsuperscript{32} \textit{E.g.}, APPA, Bonneville, California ISO, ColumbiaGrid, Consolidated Edison, \textit{et al.}, Dayton Power and Light, EEI, Entergy, Midwest ISO, Southern Companies.

\textsuperscript{33} \textit{E.g.}, California ISO, Electricity Consumers Resource Council, MidAmerican, National Grid.

\textsuperscript{34} \textit{E.g.}, AWEA, Energy Future Coalition, Entergy, Exelon, ITC Holdings, Integrys, \textit{et al.}
initiative as intended to: (1) improve coordination between electric industry participants and states on the regional, interregional, and interconnection-wide levels with regard to long-term electricity policy and planning; (2) provide better quality information for industry planners and state and federal policymakers and regulators, including a portfolio of potential future supply scenarios and their corresponding transmission requirements; (3) increase awareness of required long-term transmission investments under various scenarios, which may encourage parties to resolve cost allocation and siting issues; and (4) facilitate and accelerate development of renewable or other low-carbon generation resources.\textsuperscript{35}

27. In December 2009, DOE announced award selections for much of this ARRA funding. In each interconnection, applicants awarded funds under what DOE defined as Topic A are responsible for conducting interconnection-level analysis and transmission planning. Applicants awarded funds under Topic B are to facilitate greater cooperation among states and stakeholders within each interconnection to guide the analyses and planning performed under Topic A.\textsuperscript{36} Broad participation in sessions to date related to this initiative suggest that the availability of federal funds to pursue these goals has increased awareness of the potential for greater coordination among regions in transmission planning.


\textsuperscript{36} \textit{Id.} at 4-8.
28. DOE has also been involved in the development of several recent reports that may have implications for transmission planning. In its 2008 report, 20% Wind Energy by 2030, DOE concludes that “[s]ignificant expansion of the transmission grid will be required under any future electric industry scenario. Expanded transmission will increase reliability, reduce costly congestion and line losses, and supply access to low-cost remote resources, including renewables.”

29. Similarly, in its 2009 report, Keeping the Lights On in a New World, the DOE Electricity Advisory Committee concluded that expanding and strengthening the nation’s transmission infrastructure is becoming increasingly important for two reasons: “First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically priced power. Second, the growth in renewable energy development, stimulated in part by state-adopted renewable portfolio standards (RPS) and the possibility of a national RPS, will require significant new transmission to bring these resources, which are often remotely located, to consumer load centers.”

30. The number of states that have adopted renewable portfolio standard measures, as well as the target levels set in those measures, has continued to increase. Some 30 states and the District of Columbia have now adopted renewable portfolio standard measures.

37 Department of Energy, 20% Wind Energy by 2030, at 93 (July 2008).

38 Electricity Advisory Committee, Keeping the Lights On in a New World, at 45 (Jan. 2009). The Electricity Advisory Committee was formed to provide advice to DOE in implementing the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, and in modernizing the nation’s electricity delivery infrastructure. The Electricity Advisory Committee includes representatives from industry, academia, and state government.
These measures typically require that a certain percentage of energy sales (MWh) or installed capacity (MW) come from renewable energy resources, with the target level and qualifying resources varying among the renewable portfolio standard measures.

31. In its role as the Commission-designated Electric Reliability Organization, the North American Electric Reliability Corporation (NERC) concluded that significant transmission expansion will be needed to comply with renewable mandates. Even in the absence of a national renewable portfolio standard, NERC has stated that “an analysis of the past 14 years shows that the siting and construction of transmission lines will need to significantly accelerate to maintain reliability over the coming years.”

39 In its 2009 assessment of transmission needs, NERC found that if a national renewable portfolio standard of 15 percent were adopted, an additional 40,000 miles of transmission lines would be needed and “transmission would be a key component to accommodating new resources, linking geographically remote generation to demand centers.”

III. **The Need for Reform**

32. The Commission notes that transmission planning processes, particularly at the regional level, have seen substantial improvement through compliance with Order No. 890. As noted above, these improvements have increased opportunities for customers and other stakeholders to participate in the identification of regional needs and

---


corresponding solutions, facilitating the development of more efficient and effective transmission plans. The Commission believes that the expanded cooperation and collaboration that is now occurring in transmission planning both among transmission providers and between transmission providers and their stakeholders is to be commended.

33. Although Order No. 890 became effective just a few years ago, there have been significant changes in the nation’s electric power industry in those few years that require the Commission to consider additional reforms to transmission planning and cost allocation to reflect these new circumstances. These changes have been widely recognized within the industry.\footnote{For example, a trend of increased investment in the country’s transmission infrastructure has emerged in recent years. EEI attributes that trend to, among other factors, recognition of the reliability and other developments discussed above, as well as enactment of the Energy Policy Act of 2005 and the Commission’s implementation of its new transmission pricing policies. EEI has also observed that even amid this trend of increased investment in transmission infrastructure, transmission projects that would be located in more than one state “face significant challenges for siting, permitting, cost allocation and cost recovery.” \textit{Transmission Projects: At a Glance}, Prepared by Edison Electric Institute with assistance from Navigant Consulting, Inc., February 2010, at iii-iv. EEI has also stated that “[t]hese challenges must be resolved to facilitate the movement of large quantities of renewable energy.” \textit{Transmission Projects Supporting Renewable Resources}, Prepared by Edison Electric Institute, February 2009, at iv.}

Our intention in this Proposed Rule is not to disrupt the progress that is already being made with respect to transmission planning and investment in transmission infrastructure, but rather to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-
jurisdictional services are provided at rates, terms and conditions that are just and
reasonable and not unduly discriminatory or preferential.

34. The siting, permitting, and cost allocation of transmission facilities face significant
challenges. These challenges may be present whether an interstate transmission project is
proposed to be located within a single region for which transmission planning is
conducted in accordance with Order No. 890 (i.e., an intraregional transmission facility)
or is instead proposed to be located in more than one such transmission planning region
(i.e., an interregional transmission facility). The failure to address these challenges also
can lead to increases in congestion costs. For example, PJM stated recently that prices
for new generating capacity in the eastern part of its transmission planning region have
increased due to constraints on its transmission system. Observing that capacity prices in
the western portion of PJM were $27.73 per megawatt-day, while capacity prices in the
transmission-constrained areas of PJM were between $226.15 and $247.14 per megawatt-
day, PJM noted that “the great difference in prices for the eastern portion of PJM
compared with elsewhere shows the need for increased transmission line capacity into the
region. Transmission line additions and upgrades would reduce capacity price
differences.”

35. In light of the comments and developments discussed above, one deficiency that
has arisen is the lack of a requirement for a regional transmission plan, without which the
construction of new transmission facilities could be inhibited. Additionally, in the

---

absence of such a requirement, the facilities best suited to meet the needs of a particular region may not be identified.

36. Another deficiency that has arisen since the issuance of Order No. 890 involves transmission needs driven by public policy requirements established by state or federal laws or regulations. For example, state policies to promote increased reliance on renewable energy resources, such as the renewable portfolio standard measures discussed above, accentuate the need for transmission to deliver electricity from location-constrained renewable energy resources to load centers. Other state policies, such as goals for use of energy efficiency or demand response, may lower load forecasts within a given load zone and thereby affect transmission planning determinations. In addition, states may adopt economic development policies associated with meeting energy needs that may be relevant to assumptions made in a transmission planning process. Future public policy requirements established by federal laws or regulations also could have a significant effect on transmission planning.

37. However, existing transmission planning processes generally were not designed to account for, and do not explicitly consider, these types of public policy requirements established by state or federal laws or regulations. Indeed, some comments submitted in response to the October 2009 Notice indicate that current transmission planning processes may not permit consideration of public policy requirements within regional transmission plans.  

43 E.g., Baltimore Gas and Electric, Eastern PJM Governors, ITC Holdings, LS (continued)
finds that the failure to account explicitly for such public policy requirements in the transmission planning process may result in undue discrimination and rates, terms, and conditions of service that are not just and reasonable.

38. A third deficiency involves obstacles to nonincumbent transmission project developers’ participation in regional transmission planning processes. The Commission in recent years has seen increasing interest in transmission investment among these developers. Such interest, however, often has been coupled with expressions of concern about the treatment of merchant and independent transmission project developers in relevant transmission planning processes. Many commenters raised similar concerns in response to the October 2009 Notice, describing what they see as remaining opportunities for undue discrimination against nonincumbent transmission project developers in transmission planning processes. Such undue discrimination could discourage these developers from presenting projects in regional transmission planning processes, which, in turn, could inhibit development of beneficial transmission facilities.

39. A fourth deficiency involves the relative lack of coordination between transmission planning regions. In Order No. 890, the Commission found that when transmission providers engage in regional transmission planning, they may identify solutions to regional needs that are more efficient than those that would have been

44 See, e.g., Green Energy Express LLC, 129 FERC ¶ 61,165 (2009); Western Grid Dev., LLC, 130 FERC ¶ 61,056 (2010); Pioneer Transmission LLC, 126 FERC ¶ 61,281 (2009).
identified if needs and potential solutions were evaluated only independently by each individual transmission provider.\textsuperscript{45} Similarly, in the absence of coordination between transmission planning regions, transmission providers may not identify more efficient and cost-effective solutions to the individual needs identified in their respective utility-level and regional transmission planning processes, potentially including interregional transmission projects. In the few years since the issuance of Order No. 890, interest in multiregional facilities has grown significantly.\textsuperscript{46} The October 2009 Notice observed that the lack of coordinated planning over the seams of current transmission planning regions could be needlessly increasing costs for customers of individual transmission providers. Accordingly, the Order No. 890 transmission planning requirements may not be just and reasonable in that they may not be sufficient to address the need for greater coordination in interregional transmission planning.

40. Finally, we preliminarily conclude that existing methods for allocating the costs of new transmission may not be just and reasonable because they may inhibit the development of efficient, cost-effective transmission facilities necessary to produce just and reasonable rates. While challenges associated with allocating the cost of transmission are not new, those challenges appear to have become more acute as the need

\textsuperscript{45} “The coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis.” Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

for transmission infrastructure has grown. For example, the expansion of regional power markets and the increasing adoption of state policies to promote increased reliance on renewable energy resources have led to a growing need for regional or interregional transmission facilities. Meanwhile, determining the benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple utilities’ transmission systems and therefore may have multiple beneficiaries. In such circumstances, any individual beneficiary of a project has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development.

41. Moreover, as stated in the October 2009 Notice, constructing new transmission facilities requires a significant amount of capital. Therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. However, there are few rate structures in place today that provide for the allocation and recovery of costs for projects that are proposed to be located either within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region. The lack of such rate structures creates significant risk for transmission project developers that they will have no identified group of customers from which to recover the cost of their investment.

42. Therefore, the Commission proposes to reform transmission planning and cost allocation processes as described in the following sections of this Proposed Rule. Although focused on discrete aspects of the transmission planning and cost allocation processes, these reforms are integrally related and should be understood as a package.
With these related reforms, more transmission projects would be considered in the transmission planning process on an equitable basis, and more facilities that are included in transmission plans are likely to move forward to construction.

43. The Commission recognizes that many of the existing regional transmission planning processes are comprised of both public utility and non-public utility transmission providers. Consistent with the approach taken in Order No. 890,47 the Commission expects all public utility and non-public utility transmission providers to participate in the regional transmission planning and cost allocation processes proposed by this Proposed Rule. Reciprocity dictates that non-public utility transmission providers that take advantage of open access, including improved regional transmission planning and cost allocation, should be subject to the same requirements as public utility transmission providers. We are encouraged, based on the efforts that followed Order No. 890, that both public utility and non-public utility transmission providers collaborate in a number of regional transmission planning processes. We therefore do not believe it is necessary at this time to invoke our authority under FPA section 211A, which allows us to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis. However, if the Commission finds on the appropriate record that non-public utility transmission providers are not participating in the regional transmission planning and cost allocation processes

---

47 Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 441.
proposed in this Proposed Rule, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

IV. Proposed Reforms: Transmission Planning

44. Transmission planning is a critical component of the provision of transmission service in interstate commerce. Among other purposes, transmission planning is the means by which the transmission needs of a given area and the facilities that are best suited to meet those needs are identified. Based on the comments received in response to the October 2009 Notice and the other developments and considerations discussed above, the Commission believes that further steps with respect to transmission planning may be necessary to protect against unjust and unreasonable rates, terms and conditions and undue discrimination in the provision of Commission-jurisdictional services.

A. Participation in the Regional Planning Process

45. In Order No. 890, the Commission adopted a regional participation principle as a necessary component of a public utility transmission provider’s transmission planning process. To meet that principle, the Commission required that each public utility transmission provider coordinate with interconnected systems to: (1) share system plans to ensure that the plans are simultaneously feasible and otherwise use consistent assumptions and data; and (2) identify system enhancements that could relieve congestion or integrate new resources.\(^{48}\) This requirement for coordination at the regional level can be contrasted with the separate requirement in Order No. 890 that each

\(^{48}\) Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.
public utility transmission provider use an open and transparent process to develop a transmission plan for its own control area.\textsuperscript{49} In other words, by adopting the regional participation principle, the Commission did not require development of a comprehensive regional transmission plan.

46. The Commission explained that in complying with the regional participation principle, the specific features of a public utility transmission provider’s regional transmission planning process should take account of and accommodate, where appropriate, existing institutions, as well as historical practices and the physical characteristics of the region.\textsuperscript{50} The Commission recognized that regional transmission planning already occurs, for example, as part of the NERC Regional Entity planning process.\textsuperscript{51} The Commission urged public utility transmission providers to closely examine whether improvements in these regional transmission planning processes could be implemented to satisfy the requirements of Order No. 890 imposed on individual transmission providers.\textsuperscript{52}

47. The Commission also stated that to satisfy the regional participation principle, an existing transmission planning process must be open and inclusive and address both reliability and economic considerations.\textsuperscript{53} The Commission required each public utility

\textsuperscript{49} \textit{Id.} P 494, 523.

\textsuperscript{50} \textit{Id.} P 524.

\textsuperscript{51} \textit{Id.} P 528.

\textsuperscript{52} \textit{Id.} P 526.

\textsuperscript{53} \textit{Id.} P 528.
transmission provider to participate in a transmission planning process that facilitates regional participation and that is open to all interested customers and stakeholders.\textsuperscript{54} However, the Commission did not require each regional transmission planning process to comply with each of the nine transmission planning principles established in Order No. 890.\textsuperscript{55}

48. On compliance with these Order No. 890 requirements, many public utility transmission providers relied on existing regional entities and transmission planning processes, modified as necessary, to comply with the regional participation principle.\textsuperscript{56}

49. Since the issuance of Order No. 890, it has become apparent to the Commission that Order No. 890’s regional participation principle may not be sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process. Without such a process, each transmission provider will not have information needed to assess proposed projects and determine which project or group of projects could satisfy local and regional needs more efficiently and cost-effectively. As a result, the rates, terms and conditions of transmission services may not be just and

\textsuperscript{54} Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 226.
\textsuperscript{56} As we note above, the regional transmission planning processes that public utility transmission providers in regions outside of RTOs and ISOs have relied on to comply with certain requirements of Order No. 890 are North Carolina Transmission Planning Collaborative, Southeast Inter-Regional Participation Process, SERC Reliability Corporation, ReliabilityFirst Corporation, Mid-Continent Area Power Pool, Florida Reliability Coordination Council, WestConnect, ColumbiaGrid, and Northern Tier Transmission Group.
reasonable. For example, greater regional coordination in transmission planning would expand opportunities for transmission providers, their transmission customers, and other stakeholders to identify and implement regional solutions to local and regional needs that are more cost-effective than those proposed in the transmission planning process of individual transmission providers. In addition, more effective regional transmission planning could better facilitate the integration of location-constrained renewable energy resources, which may be needed to fulfill public policy requirements such as the renewable portfolio standards adopted by many states.

50. Given this concern, we propose to require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that meets the following transmission planning principles established in Order No. 890: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies.  

51. More specifically, we propose to require that each regional transmission planning process consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that cost-effectively meet the needs of transmission providers, their

---

This proposal does not include the regional participation principle and cost allocation for new projects principle of Order No. 890 because we address interregional coordination in transmission planning and cost allocation for transmission facilities included in a regional transmission plan elsewhere in this Proposed Rule.
transmission customers, and other stakeholders. When an individual transmission provider engages in local transmission planning, it considers and evaluates transmission facilities and non-transmission solutions that are proposed and then develops a local transmission plan that identifies what transmission facilities are needed to meet the needs of its native load (if any), transmission customers, and other stakeholders. Likewise, the regional transmission planning process would consider and evaluate transmission facilities and non-transmission solutions that are proposed and develop a regional transmission plan that identifies what transmission facilities are needed to meet the needs of transmission customers and other stakeholders in the region.

In addition, because of the increased importance of regional transmission planning that is designed to produce a regional transmission plan, transmission customers and other stakeholders must be provided with an opportunity to participate meaningfully in that process. Therefore, we propose to apply the above-noted Order No. 890

---

58 When evaluating potential solutions to identified needs, transmission providers must evaluate proposals for transmission, generation, and demand resources against one another based on criteria set forth in their tariffs. See Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494-95; Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216. The Commission also has recognized that in appropriate circumstances alternative technologies may be eligible for treatment as transmission for ratemaking purposes. Western Grid, 130 FERC ¶ 61,056 (2010).

59 As noted in Order No. 890, the planning obligations proposed here do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438. As also noted in Order No. 890, the ultimate responsibility for transmission planning remains with transmission providers. With that said, the Commission fully intends that the transmission planning processes provide for the timely and meaningful input and participation of customers into the development of transmission plans. Id. P 454.
transmission planning principles to the regional transmission planning process, which would ensure that transmission customers and other stakeholders can express their needs before a regional transmission plan is finalized and thus help to identify solutions that more efficiently address the region’s needs. Similarly, ensuring access to the models and data used in the regional transmission planning process would allow transmission customers and other stakeholders to determine if their needs are being addressed in a cost-effective manner. Greater access to information and transparency would also help transmission customers and other stakeholders to recognize and understand the benefits that they will receive from a transmission facility that is included in a regional transmission plan. This consideration is particularly important in light of our proposal below to require that each public utility transmission provider have a cost allocation method for transmission facilities included in its regional transmission plan that reflects the benefits that those facilities provide.

53. Although the explicit requirement for a public utility transmission provider to participate in a regional transmission planning process that complies with the Order No. 890 transmission planning principles identified above would be new, we note that the existing regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these requirements.

54. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule.
B. **Public Policy Driven Projects**

55. In Order No. 890, the Commission included an Economic Planning Studies principle among the nine transmission planning principles. The Commission stated that its primary objective in adopting that principle was “to ensure that the transmission planning process encompasses more than reliability considerations.”\(^{60}\) The Commission explained that although planning to maintain reliability is a critical priority, transmission planning also involves economic considerations.\(^{61}\)

56. More specifically, the Commission stated that when conducting transmission planning to serve native load customers, a prudent vertically integrated transmission provider will plan not only to maintain reliability, but also consider whether transmission upgrades or other investments can reduce the overall costs of serving native load.\(^{62}\) The Commission identified this potential for undue discrimination among a transmission provider’s customers as a justification to implement the Economic Planning Studies principle requiring transmission providers to make available to their customers services that are comparable to those they are performing on behalf of their native loads.\(^{63}\)

57. The Economic Planning Studies principle requires that stakeholders be given the right to request a defined number of high priority studies annually through the

---

\(^{60}\) Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 542.

\(^{61}\) Id.

\(^{62}\) Id. The Commission further stated that such upgrades could, for example, reduce congestion (redispach) costs or integrate efficient new resources (including demand resources) and new or growing loads. Id.

\(^{63}\) Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 240.
transmission planning process. As defined in Order No. 890, these high priority studies are intended to identify solutions that could relieve transmission congestion or integrate new resources and loads, including upgrades to integrate new resources or loads on an aggregated or regional basis.\textsuperscript{64}

58. In Order No. 890, the Commission also required each public utility transmission provider to coordinate its transmission planning activities with the relevant state and local regulatory authorities that choose to participate in the transmission planning process and stated its expectation that “all transmission providers will respect states’ concerns.”\textsuperscript{65} As such, state and local regulatory authorities may fully participate in the existing Order No. 890 transmission planning process and identify, among other issues, public policy requirements established by state or federal laws or regulations that they see as relevant to transmission needs. However, when choosing whether to include a proposed transmission project in its local or regional transmission plan, a public utility transmission provider has no explicit obligation under Order No. 890 or the \textit{pro forma} OATT to evaluate the project based on its potential to facilitate the achievement of public policy requirements established by state or federal laws or regulations.

59. The October 2009 Notice observed that some areas are struggling with how to adequately address transmission expansion necessary to, for example, integrate renewable generation resources into the transmission system. The October 2009 Notice

\textsuperscript{64} Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 547-48.

\textsuperscript{65} \textit{Id.} P 574.
attributed these difficulties in part to the fact that planning transmission facilities necessary to meet state resource requirements, such as the renewable portfolio standard measures discussed above, must be integrated with existing transmission planning processes that are based on metrics or tariff provisions focused on reliability or in some cases production cost savings. Drawing on these observations, the October 2009 Notice sought comment as to whether reliability impact studies are properly aligned with evaluations of economic-based projects or projects proposed to satisfy renewable energy standards. To the extent that assessments of various possible project benefits are not properly aligned, the October 2009 Notice sought comment as to how reliability assessments, economic evaluations and assessments of a project’s ability to meet public policy goals could be aligned to better identify options that meet all of these regional needs.

60. The Commission received a number of comments on these issues, expressing a range of opinions. Several commenters argue that the existing transmission planning and stakeholder processes properly align reliability impact studies with evaluations of other projects designed to meet economic-based or public policy requirements. Other

66 October 2009 Notice at 3.

67 Id. at 4.

68 E.g., Dominion, Entergy, Large Public Power Council, Midwest ISO, New York PSC, Northern Tier Transmission Group, Southern Companies, WestConnect Planning Parties, and WECC. In addition, PSEG Companies state that while it is true that reliability impact studies are performed independently of economic planning, such a distinction is appropriate because ensuring reliability is the primary objective of the planning process.
commenters suggest that it would be inappropriate for the Commission to require that renewable energy standards be incorporated into the transmission planning process.  

For example, Public Power Council contends that the Commission lacks jurisdiction to require that the resources necessary to comply with state renewable energy standards are accounted for in the transmission planning process, as such standards are state-level policies.

61. In addition, several commenters recommend that the Commission incorporate public policy objectives into the transmission planning process. For example, PJM argues that “additional guidance from the Commission is needed if public policy imperatives such as aggressive integration of renewable resources are to be met.” PJM states that while ensuring system reliability should remain the primary goal of the transmission planning process, providing for incorporation of public policy objectives, where applicable, could facilitate cost-effective achievement of those objectives. In particular, PJM suggests that the Commission move beyond a strict application of “bright line” criteria currently used for reliability and economic projects and allow transmission

---

69 E.g., Massachusetts Departments and Public Power Council.

70 Massachusetts Departments share a similar concern.


72 PJM Order No. 890 Technical Conference Comments, op. cit. at 6.
providers more flexibility to take into account the multiple reliability, economic, or public policy-based benefits a single project may be able to provide.\textsuperscript{73}

62. Other commenters propose various approaches to incorporating public policy objectives into the transmission planning process. Some of these commenters argue that if the goal of the transmission planning process is to allow load-serving entities to satisfy their resource needs, such needs could include resources required to comply with state and federal public policy objectives.\textsuperscript{74} Still other commenters recommend that the Commission provide flexibility in the transmission planning process so that each region can determine which resources it will use to fulfill any applicable public policy objectives.\textsuperscript{75}

63. To ensure that each public utility transmission provider’s transmission planning process supports rates, terms, and conditions of transmission service in interstate commerce that are just and reasonable and not unduly discriminatory or preferential, the Commission preliminarily finds that transmission needs driven by public policy requirements established by state or federal laws or regulations should be taken into account in the transmission planning process. Indeed, consideration of such public policy requirements raises issues similar to those raised in the Commission’s discussion in Order

\textsuperscript{73} Citing, PJM Interconnection, L.L.C., 119 FERC ¶ 61,265 (2007) (directing PJM to adopt a formulaic approach to applying metrics used to choose economic projects).

\textsuperscript{74} E.g., APPA and Bay Area Municipal Transmission Group.

\textsuperscript{75} E.g., Consolidated Edison, et al.
No. 890 of the Economic Planning Studies principle. When conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to enable compliance with relevant public policy requirements established by state or federal laws or regulations in a cost-effective manner. Therefore, we propose to find that, to avoid acting in an unduly discriminatory manner, a public utility transmission provider must consider these same needs on behalf of all of its customers. In addition, providing for incorporation of public policy requirements established by state or federal laws or regulations in transmission planning processes, where applicable, could facilitate cost-effective achievement of those requirements.

64. To address these issues, we propose to revise the requirements established in Order No. 890 with respect to local and regional transmission planning processes. Specifically, we propose to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide

---

76 In Order No. 890, the Commission intended the economic planning studies principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including upgrades to integrate new resources and loads on an aggregated or regional basis. The Commission recognizes that its statements with respect to the economic planning studies principle may have contributed to confusion as to whether public policy requirements may be considered in the transmission planning process.

77 By “local” transmission planning process, we mean the transmission planning process that a public utility transmission provider performs for its individual service territory or footprint pursuant to the requirements of Order No. 890.
for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs. After consulting with stakeholders, a public utility transmission provider may include in the transmission planning process additional public policy objectives not specifically required by state or federal laws or regulations. This proposed requirement would be a supplement to, and would not replace, any existing requirements with respect to consideration of reliability needs and application of the economic studies principle in the transmission planning process.

65. The Commission does not propose to identify the public policy requirements established by state or federal laws or regulations that must be considered in individual local and regional transmission planning processes. Instead, we propose to require each public utility transmission provider to coordinate with its customers and other stakeholders to identify public policy requirements established by state or federal laws or regulations that are appropriate to include in its local and regional transmission planning processes.

66. We propose to require each public utility transmission provider to specify in its OATT the procedures and mechanisms in its local and regional transmission planning processes for evaluating transmission projects proposed to achieve public policy requirements established by state or federal laws or regulations. If a public utility transmission provider believes that its existing transmission planning processes satisfy these requirements, then it must make that demonstration in its compliance filing.

67. This proposed requirement is intended to clarify the objectives that would be considered in local and regional transmission planning processes. As we stated in Order
No. 890, we believe that the transparency provided under open transmission planning processes can provide useful information that would help states to coordinate transmission and generation siting decisions, allow consideration of regional resource adequacy requirements, facilitate consideration of demand response and load management programs at the state level, and address other factors states wish to consider.

68. Another benefit of this proposed requirement to consider public policy requirements established by state or federal laws or regulations within the transmission planning process is that adherence with this proposed requirement may eventually increase the proportion of transmission network investment that is constructed pursuant to proactive transmission planning processes, thereby reducing the proportion of network upgrades that would otherwise be triggered by individual generator interconnection requests, which can be time consuming and inefficient. If more of the transmission network were expanded under the type of regional transmission planning process described above, then the network upgrades triggered by interconnection requests should be less significant in size and cost than they have been in the past and the associated differences in cost allocation provisions may become less significant as well.

69. This proposed requirement is not intended in any way to infringe upon state authority with respect to integrated resource planning. In addition, to the extent that a public utility transmission provider has an obligation to comply with public policy requirements established by state or federal laws or regulations, such as the state

78 Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 479, n.274.
renewable portfolio standard measures discussed above, this proposed requirement is not intended to convert a failure to satisfy that obligation into a violation of its OATT. In other words, while a public utility transmission provider would be required to identify and consider public policy requirements established by state or federal laws or regulations in its local and regional transmission planning processes, this proposed requirement would not establish an independent obligation to satisfy those requirements.

70. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule. In particular, we seek comment as to whether public policy requirements established by state or federal laws or regulations should be considered in the transmission planning process. Further, we seek comment on how planning criteria based on public policy requirements should be formulated, including whether it is more appropriate to use flexible criteria instead of “bright line” metrics when determining which projects are to be included in the regional transmission plan, whether the use of flexible criteria would provide undue discretion as to whether a project is included in a regional transmission plan, and whether the use of “bright line” metrics may inappropriately result in alternating inclusion and exclusion of a single project over successive planning cycles and therefore create inappropriate disruptions in long-term transmission planning.
C. Opportunities for Undue Discrimination against Nonincumbent Transmission Developers

1. Nonincumbent Transmission Developer Participation in the Transmission Planning Process

71. As discussed above, Order No. 890 sought to reduce opportunities for undue discrimination and preference in the provision of transmission service. With regard to the transmission planning process, the Commission established nine transmission planning principles to prevent undue discrimination. However, Order No. 890 did not specifically address the potential for undue preference to incumbent utilities over nonincumbent transmission developers through practices applied within transmission planning processes.

72. The October 2009 Notice observed that in some areas, when a nonincumbent transmission developer participates in the transmission planning process, it may lose the opportunity to construct its proposed project to the incumbent transmission owner if that owner has a right of first refusal to construct any transmission facility in its service territory. The October 2009 Notice also observed that in some areas, merchant transmission developers choose to plan proposed facilities outside of the transmission providers’ planning processes.\(^7^9\)

73. The October 2009 Notice posed several questions relating to merchant and independent transmission developers’ participation in the regional transmission planning process. The October 2009 Notice sought comment on how projects proposed by

\(^{79}\) October 2009 Notice at 3.
merchant or independent transmission developers should be treated in the regional transmission planning process. The October 2009 Notice also asked whether these types of developers should be required to participate in the regional transmission planning process and, if so, at what point they should be required to engage in that process. In addition, the October 2009 Notice asked whether the right of first refusal for incumbent transmission owners unreasonably impedes the development of merchant and independent transmission and, if so, how that impediment could be addressed. Finally, the October 2009 Notice asked whether there are barriers to merchant and independent transmission developers’ participation in the regional transmission planning process other than rights of first refusal.  

74. These questions generated extensive comments. For example, many commenters argue that a project proposed by a merchant or independent transmission developer should be treated on the same basis as all other proposed projects. Also, a number of commenters assert that merchant and independent developers should be required to participate in the transmission planning process. For example, Southern Companies

---

80 Id. at 4.
82 E.g., APPA, CAilifornians for Renewable Energy, Delaware Municipal and Southwestern Electric, Dominion, Exelon, Integrys, Old Dominion, Sun Flower and Mid-Kansas, Large Public Power Council, Midwest ISO, National Nuclear Security Administration Service Center, National Rural Electric Coops, New England States’
asserts that it would be discriminatory if the Commission did not require merchant and independent developers to participate in the transmission planning process, as jurisdictional and non-jurisdictional transmission providers are required to do.

75. Other commenters state that merchant and independent developers should not be treated similarly or required to participate in the transmission planning process. For example, Chinook and Zephyr and ITC Holdings state that because the business model of merchant and independent transmission developers is different from that of vertically-integrated utilities, different transmission planning requirements are appropriate for them. Chinook and Zephyr also argue that regional transmission planning requirements should apply to a merchant developer only after it is operating under a Commission-approved OATT. Dayton Power and Light contends that while any transmission facility that is necessary to meet NERC reliability criteria, regardless of ownership, should be required to be included in the transmission planning process, merchant and independent projects planned for nonreliability reasons can be developed independently of the transmission planning process, subject to appropriate interconnection requirements.

76. Other commenters emphasize the importance of allowing merchant and independent developers to participate actively in the transmission planning process.\(^{83}\)

\(^{83}\) E.g., Green Energy Express, ITC Holdings, Pattern Transmission, and Starwood.
Generally, these commenters argue that merchant and independent transmission developers should either participate in the transmission planning process as early as practical, at the beginning of the transmission planning cycle, or as soon as they have a proposal that is developed well enough to be considered. Pattern Transmission also suggests that the Commission should better define the transmission planning process and the roles of its participants to ensure a level playing field for independent transmission developers.

77. The questions about whether an incumbent transmission owner’s right of first refusal unreasonably impedes merchant or independent transmission development and, if so, how this impediment could be addressed, also generated extensive comments. Many commenters state that a right of first refusal does not unreasonably impede merchant and independent transmission development. Various commenters present a range of reasons that it is appropriate for an incumbent transmission provider to have a right of first refusal, including that the incumbent transmission owner: (1) has a legally enforceable obligation to maintain reliability on its systems and faces penalties for

---

84 *E.g.*, Allegheny Companies, AEP, Ameren, Baltimore Gas and Electric, Dominion, EEI, Great River Energy, Integrys, et al., Sun Flower and Mid-Kansas, Large Public Power Council, MidAmerican, Midwest ISO Transmission Owners, National Grid, Northern Tier Transmission Group, Old Dominion, PPL, PSEG Companies, Ohio Commission, San Diego Gas & Electric, Southern California Edison, Southern Companies, WestConnect Planning Parties, and Xcel. However, Old Dominion suggests that the Commission could eliminate the right of first refusal if merchant and independent transmission developers were subject to the same rules and had the same responsibilities as incumbent transmission owners, and could recover their costs through the RTO/ISO tariff.
noncompliance; (2) is obligated under state law to provide reliable service at the lowest reasonable cost; (3) may be required to build facilities included in an RTO’s or ISO’s regional plan, an obligation that merchant and independent transmission developers lack; (4) is best situated to develop transmission facilities within its service territory, as it is most familiar with the design and operation of its system, its customers’ needs, and state and local permitting and siting processes; and (5) may be able to provide transmission services at a lower cost than a merchant or independent transmission developer because it enjoys economies of scale with respect to the staff and resources necessary to maintain and operate new transmission facilities.

78. Some commenters contend that the right of first refusal should be preserved because an incumbent transmission owner that voluntarily joined an RTO or ISO did so with the understanding that it would retain the right to invest in and earn a return on new facilities within its system.\(^\text{85}\) According to Midwest ISO Transmission Owners, eliminating a right of first refusal could provide a disincentive for RTO membership. Similarly, the California ISO asserts that without a right of first refusal, a transmission owner may have less incentive to participate in an RTO or ISO.

79. However, other commenters argue that a right of first refusal impedes transmission development and provides an undue advantage to an incumbent transmission owner.\(^\text{86}\)

---

\(^{85}\) *E.g.*, Ameren, MidAmerican, and Midwest ISO Transmission Owners.

Such commenters present a number of reasons for eliminating a right of first refusal, including the following: (1) a right of first refusal provides a disincentive for a merchant or independent developer to propose a project, especially a proposal for a transmission facility that spans multiple utilities’ service territories, because any investment that it makes in developing a proposal may be lost if an incumbent transmission owner can exercise its right of first refusal or otherwise delay the project or prevent construction of the project; (2) by discouraging competition and new entry, a right of first refusal likely increases costs to ratepayers; and (3) a merchant or independent transmission developer may have difficulty obtaining financing if investors perceive that its proposed project could be subject to a right of first refusal or is otherwise at a disadvantage compared to a project sponsored by an incumbent transmission owner.

80. Among other comments on this issue, Startrans claims that for an incumbent transmission owner, a Commission-approved right of first refusal effectively creates a federal franchise for transmission development derived from a state franchise for retail electricity. Transmission Agency of Northern California contends that a right of first refusal also may “diminish the incentive for the incumbent utilities to conceive projects in their own service territory.”

81. Responding to arguments in favor of a right of first refusal, some commenters argue that concerns about the reliability of a merchant or independent transmission

---

Study Group, Transmission Agency of Northern California, and Transmission Dependent Utility Systems.

87 Transmission Agency of Northern California at 3.
developer’s project are unfounded, as the merchant or independent transmission
developer will be subject to NERC reliability standards and to the same penalties for
noncompliance as an incumbent transmission owner.\textsuperscript{88} Pattern Transmission states that a
merchant or independent developer has a financial incentive to construct and operate
facilities safely and reliably in accordance with all applicable regulatory and industry
standards, as its investment is at risk if it does otherwise. With regard to an incumbent
transmission owner’s obligation to build, some commenters assert that it is not a burden,
but rather a privilege, as the incumbent transmission owner is assured the opportunity to
recover its costs and earn a return on its investment through the rate base. These
commenters argue that a merchant or independent developer would be willing to compete
for such an obligation.\textsuperscript{89} In response to concerns that a merchant or independent
developer would submit an inaccurately low bid to construct a proposed transmission
facility, some commenters claim that such a developer is no more likely to do so than an
incumbent transmission owner.\textsuperscript{90} These same commenters argue that, contrary to what
some commenters assert, an incumbent transmission owner will not leave an RTO or ISO
if the right of first refusal is eliminated.

82. While some commenters advocate elimination of all rights of first refusal, other
commenters support more limited restrictions. For example, Exelon states that “where an
independent developer bids on transmission expansion that is justified under existing

\textsuperscript{88} E.g., Green Energy Express and Pattern Transmission.
\textsuperscript{89} E.g., Indicated Partners and Startrans.
\textsuperscript{90} E.g., Indicated Partners.
planning criteria and will be included in rate base, the incumbent transmission owner should be required to match the bid to invoke its right of first refusal.”

Several commenters argue that a right of first refusal should be allowed for reliability-based projects, but may not be necessary for economic-based or other projects. While AWEA and LS Power both maintain that the right of first refusal should be eliminated, they contend that if the right of first refusal is preserved then those practices should apply only to local reliability projects. Moreover, AWEA asserts that a right of first refusal should be required to be exercised within ninety days. Similarly, ITC Holdings contends that a right of first refusal will continue to impede transmission development if the time for exercising it is allowed to continue indefinitely, and Pacific Gas and Electric argues that any right of first refusal should be exercised in a timely manner. Transmission Access Policy Study Group, however, states that the Commission may need to take other steps in addressing this issue in addition to limiting the time in which a right of first refusal may be exercised. In addition, several commenters contend that placing restrictions on a right of first refusal makes the practice no less discriminatory.

83. EEI argues that while “in general, applicability of a right of first refusal does not create an impediment to transmission planning or development” and that in many cases, “incumbent transmission owners are better situated to build needed transmission within their franchised service territories,” if the Commission finds it necessary to address the

---

91 Exelon at 12.
92 E.g., Allegheny Companies, Dominion, Large Public Power Council, and SPP.
93 E.g., Indicated Partners.
exercise of a right of first refusal, it should do so on a case-specific basis. Similarly, the California ISO recommends that the Commission allow the right of first refusal to be addressed through individual RTO and ISO stakeholder processes, rather than adopting generic right of first refusal regulations. Pacific Gas and Electric states that this proceeding should not preempt the California ISO’s development of a right of first refusal proposal. In contrast, SPP states that additional clarification and a generally applicable policy regarding the right of first refusal is necessary. The Organization of MISO States argues that, while a right of first refusal may limit competition, any modifications must recognize various state regulatory structures and respect state jurisdiction and statutes. The Alabama PSC argues that the Commission should adopt policies that encourage merchant transmission development only if the state commissions in a region support such policies.

84. In response to the question in the October 2009 Notice regarding barriers to merchant and independent transmission developers’ participation in the regional transmission planning process other than a right of first refusal, several commenters state that there are none or that they are unaware of any. However, Pattern Transmission suggests that the uncertainty of recovering the costs associated with participation in the transmission planning process can be a barrier to participation by merchant and independent transmission developers, particularly if the planning process is inefficient.

---

94 EEI at 9-10.

and deadlines are not met. Pattern Transmission also asserts that an incumbent transmission owner has an advantage in developing proposals as it has priority access to data. Green Energy Express states that the Commission should ensure “a level playing field with regard to the flow of information, the determination of need, and related interactions between an RTO or ISO or other transmission planning region, incumbent transmission owners and developers, and independent, nonincumbent developers.”

85. LS Power states that there are several additional barriers to third party developers’ participation in regional transmission planning processes, some of which are unique to certain markets. For example, LS Power states that there are regions in which an independent developer cannot become a transmission owner until it has completed a project and owns the resulting transmission facility. Additionally, LS Power states that it is difficult to develop a project in a region where the load-serving entity is also a transmission owner, as the incumbent utility is often responsible for both generation and transmission planning and resource procurement and may have an incentive to expand its rate base by investing in transmission infrastructure rather than support independent transmission development.

86. Northern Tier Transmission Group suggests that some merchant transmission developers self-impose a barrier to successful participation in the transmission planning process in that they do not submit comparable planning data. As such, Northern Tier Transmission Group is unable to include their projects in its analytical studies.

96 Green Energy Express at 10.
2. **Proposed Reforms Regarding Nonincumbents**

87. Based on the comments submitted in response to the October 2009 Notice, there appear to be opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. Where an incumbent transmission provider has a right of first refusal, a nonincumbent transmission developer risks losing its investment in developing a proposal for submittal to the regional transmission planning process, even if that proposal is selected for inclusion in the regional transmission plan. We are concerned that it may be unduly discriminatory or preferential to deny a nonincumbent transmission developer that sponsors a project that is included in a regional transmission plan the rights of an incumbent transmission provider that are created by a transmission provider’s OATT or agreements subject to the Commission jurisdiction.

88. In addition, under these circumstances, nonincumbent transmission developers may be less likely to participate in the regional transmission planning process. If the regional transmission planning process does not consider and evaluate projects proposed by nonincumbents, it cannot meet the principle of being “open.” Moreover, such a planning process may not result in a cost-effective solution to regional transmission needs and projects that are included in a transmission plan therefore may be developed at a higher cost than necessary. The result may be that regional transmission services may be provided at rates, terms and conditions that are not just and reasonable.

89. To address these issues, we propose a framework that reflects the following reforms, including the elimination from a transmission provider’s OATT or agreements
subject to the Commission’s jurisdiction of provisions that establish a federal right of first refusal for an incumbent transmission provider with respect to facilities that are included in a regional transmission plan. Neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a regional transmission planning process. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. The Commission proposes that the tariff changes to implement these proposed reforms would be developed through an open and transparent process involving the public utility transmission provider, its customers, and other stakeholders.

90. First, we propose to require that each public utility transmission provider must revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity’s eligibility to propose a project in the regional transmission planning process, whether that entity is an incumbent transmission owner or a nonincumbent transmission developer. These criteria must be included in the public utility transmission provider’s OATT and must not be unduly discriminatory or preferential. However, it would not be unduly discriminatory or preferential to have appropriate qualification criteria for all potential transmission owners. Such criteria should be designed to demonstrate that each potential transmission owner has the necessary financial and technical expertise to develop,
construct, own, operate, and maintain transmission facilities. Any such criteria must be approved by the Commission. Although we do not propose here to establish a single set of qualification criteria that would apply in all regional transmission planning processes, we seek comment on whether we should do so and if so, what these criteria should be. Instead, we propose that each public utility transmission provider, in cooperation with customers and other stakeholders in its transmission planning region, must participate in a regional transmission planning process that develops qualification criteria that satisfy the requirements of this Proposed Rule.

91. Second, we propose to require that each public utility transmission provider must revise its OATT to include a form by which a prospective project sponsor would provide information in sufficient detail to allow the proposed project to be evaluated in the regional transmission planning process. In connection with the other aspects of the framework discussed in this section, we also propose to require that all proposals to be considered in a given transmission planning cycle must be submitted by a single, specified date, to minimize the opportunity for other entities to propose slight modifications to already submitted projects.

97 Nothing would preclude the incumbent transmission owner from agreeing to operate and maintain the facilities. Additionally, nothing in this Proposed Rule is intended to change existing RTO and ISO operational procedures and practices.

98 The information about its proposed project that a sponsor provides also should include, as relevant, engineering studies, cost analyses, and any other detailed reports completed by the project sponsor as needed to facilitate evaluation of the project in the regional transmission planning process.
92. Third, we propose to require that each public utility transmission provider participate in a regional transmission planning process that evaluates the proposals submitted to the regional planning process through a transparent and not unduly discriminatory or preferential process. Each public utility transmission provider would be required to describe in its OATT the process used for evaluating whether to include a proposed transmission facility in the regional transmission plan.  

93. Fourth, with respect to facilities that are included in a regional transmission plan, we propose to require removal from a transmission provider’s OATT or agreements subject to the Commission’s jurisdiction provisions that establish a federal right of first refusal for an incumbent transmission provider. We also propose to require each public utility transmission provider to amend its OATT to describe how the regional transmission planning process in which it participates provides for the sponsor (whether an incumbent transmission provider or a nonincumbent transmission developer) of a facility that is selected through the regional transmission planning process for inclusion in

99 The description would need to provide sufficient detail so that an entity that proposed a project could determine why the project was included or not included in the regional transmission plan. In addition to addressing concerns about undue discrimination or preference, the description would facilitate understanding of the relative weight placed on various benefits associated with competing proposals (e.g., one proposal might address only a reliability-driven transmission need, while another proposal might also provide greater benefits in terms of congestion relief or advancement of public policy requirement established by state or federal laws or regulations that a transmission planning region has identified).

100 If a Commission-approved tariff or agreement contains a reference to a right provided under state or local laws or regulations, such a provision would not be subject to this requirement.
the regional transmission plan to have a right, consistent with state or local laws or regulations, to construct and own that facility.

94. Moreover, because a regional transmission planning process may result in modifications to proposed projects in order to better meet the needs of the region, the public utility transmission provider must ensure that its regional transmission planning process has a mechanism to determine which proposal the modified project is most similar to, with the sponsor of the most similar project having the right, consistent with state or local laws or regulations to construct and own the facilities.

95. Fifth, we propose to require that if a proposed project is not included in a regional transmission plan and if the project’s sponsor resubmits that proposed project in a future transmission planning cycle, that sponsor would have the right to develop that project under the foregoing rules even if one or more substantially similar projects are proposed by others in the future transmission planning cycle. The OATT must state that this priority to develop the proposed facility continues for a defined period of time (e.g., for resubmission annually in subsequent transmission planning cycles over a 5-year period).

96. Sixth, we propose to require that, if an incumbent transmission project developer may recover the cost of a transmission facility for a selected project through a regional cost allocation method, a nonincumbent transmission project developer must enjoy that same eligibility. More specifically, each public utility transmission provider must participate in a regional planning process that provides that, when a project proposed by a nonincumbent transmission developer is included in a regional transmission plan, that developer must have an opportunity comparable to that of an incumbent transmission
owner to recover the costs associated with developing the project and constructing the transmission facility. Costs associated with a project that is not included in the regional transmission plan, whether proposed by an incumbent or by a nonincumbent transmission provider, may not be recovered through a transmission planning region’s cost allocation process.

97. We emphasize that these proposed reforms would apply only to facilities that are evaluated in a regional transmission planning process and selected for inclusion in a regional transmission plan. We do not propose to modify any existing obligation for an incumbent transmission owner to build unsponsored projects that are identified as necessary in a regional transmission plan.  

101 In addition, where an incumbent transmission owner has the right to build, own, and recover costs for upgrades to its own existing transmission facilities (e.g., tower change out and reconductoring), such right would not be affected by the reforms proposed here.

98. We also emphasize that these proposed reforms would affect only a right of first refusal established in a transmission provider’s OATT or agreements subject to the

---

101 For example, in some RTO and ISO regions, transmission owners have obligations to build certain transmission facilities identified by the RTO or ISO. As new transmission owners, including nonincumbent transmission owners, join the RTO or ISO, they will incur the obligations accompanying that status in the RTO or ISO’s tariff and other governing documents. We note that provisions imposing such obligations may need to be modified to reflect how they will apply to nonincumbent transmission project developers. We also note that before turning to a transmission owner with such an obligation, the RTO or ISO could conduct a competitive bidding process to assign construction rights for an unsponsored project in its regional transmission plan.
Commission’s jurisdiction. This Proposed Rule does not address, propose to change, or seek to preempt any state or local laws or regulations.

99. Finally, we do not propose here to require a transmission developer that does not seek to use the regional cost allocation process to participate in the regional transmission planning process, as some commenters recommend. For example, because a merchant transmission developer assumes all financial risk for developing its project and constructing the proposed facilities, it is unnecessary to require such a developer to participate in a regional transmission planning process for purposes of identifying the beneficiaries of its project or securing eligibility to use a regional cost allocation method. A developer that does not seek to use the regional cost allocation process nevertheless would be required to comply with all reliability requirements applicable to facilities in the transmission planning region in which its project would be located. In addition, such a developer is not prohibited from participating—and, indeed, is encouraged to participate—in the regional transmission planning process.

100. As discussed above, in response to the October 2009 Notice, many commenters link the right of first refusal for an incumbent utility to its obligation to construct new facilities if called upon to do so. While the Commission acknowledges these comments, we preliminarily find that these two practices are not, and should not be, linked within regional transmission planning processes. That is, while a public utility transmission owner may have accepted an obligation to build in relation to its membership in an RTO or ISO, this obligation is not directly dependent on that transmission provider having a corresponding right of first refusal with regard to a proposal to construct and own a new
transmission facility located in that region. What is important from the Commission’s perspective is that the documents approved by the Commission must not be unduly discriminatory. The Commission preliminarily finds that neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission approved OATT or agreement, receive different treatment in the transmission planning and selection process, and both should share similar benefits and obligations commensurate with that participation.

101. We seek comment on how the reforms proposed in this section of the Proposed Rule would affect the rights, obligations, and responsibilities of incumbent and nonincumbent transmission providers. In particular, we seek comment on the relationship or lack of relationship between a right of first refusal and an obligation to build. We also seek comment on whether it would be appropriate to retain a federal right of first refusal in an OATT or other documents subject to the Commission’s jurisdiction. If not, why not? If so, would it be appropriate to retain an obligation to build for an incumbent transmission provider while removing a federal right of first refusal for that incumbent?

D. Interregional Coordination

1. The Need for Interregional Planning Reforms

102. As discussed above, the transmission planning principles established in Order Nos. 890 and 890-A establish a framework for transmission planning at the local and regional levels. In Order No. 890-A, the Commission emphasized that effective regional planning should include coordination among regions. Further, the Commission stated that regions
and subregions should coordinate as necessary to share data, information and assumptions to maintain reliability and allow customers to consider the resource options that span the regions. In several of the Order No. 890 compliance orders, the Commission requested more detailed information regarding compliance with this aspect of the regional participation principle.

Within that Order No. 890 and 890-A framework, transmission providers in certain parts of the country have organized subregional transmission planning groups for the purpose of collectively developing plans for upgrades on their combined transmission systems. These subregional transmission plans are then analyzed at a regional level to ensure that, if implemented, they will be simultaneously feasible and meet reliability requirements. Additionally, some neighboring transmission providers have undertaken joint transmission planning pursuant to bilateral agreements. However, as observed in

---


104 Such analysis is consistent with one aspect of the Regional Participation transmission planning principle that the Commission established in Order No. 890. On that issue, the Commission stated: “[I]n addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each transmission provider will be required to coordinate with interconnected systems to: (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data, and (2) identify system enhancements that could relieve congestion of integrate new resources …” Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

the October 2009 Notice, there are few processes in place to analyze whether alternative interregional solutions would more efficiently or effectively meet the needs identified in individual regional transmission plans.106

104. The October 2009 Notice posed several questions related to this issue, including whether existing transmission planning processes are adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers. The October 2009 Notice also sought comment as to what processes should govern the identification and selection of projects that affect multiple systems.107

105. In response to the October 2009 Notice, some commenters state that the need for supplemental interregional transmission planning processes cannot be evaluated until stakeholders gain more experience with the regional transmission planning processes conducted pursuant to Order No. 890, and thus oppose Commission action on this issue at this time.108 Other commenters state that the lack of interregional planning is a considerable problem and that transmission planning could be enhanced by increasing the amount of coordination that occurs between neighboring transmission planning regions.109

106 October 2009 Notice at 2.
107 Id. at 3.
109 E.g., Duke, Exelon, NextEra, Ohio Commission, Old Dominion, Organization of MISO States, PSEG Companies, Transmission Access Policy Study Group, and (continued)
106. More specifically, several commenters advocate expansion of interregional transmission planning, but disagree as to the extent to which interregional coordination should be institutionalized. Proposals range from requiring regional transmission planning entities to comply with Order No. 890 transmission planning principles,\(^\text{110}\) to requiring greater coordination among existing transmission planning regions,\(^\text{111}\) to expanding the authorities of regional transmission planning entities.\(^\text{112}\) Some commenters suggest that the Commission should require interregional transmission planning or develop *pro forma* seams agreements that describe the requirements for coordinating transmission planning with a neighboring transmission planning region.\(^\text{113}\)

107. San Diego Gas & Electric, for example, states that, in the West, transmission planning is a hodgepodge of balkanized processes resulting in a flood of proposed interstate transmission facilities but with virtually no consideration given to which of the proposed facilities would be most effective in meeting the needs of the broadest set of constituents. San Diego Gas & Electric also states that little serious consideration is

---

\(^\text{110}\) *E.g.*, Old Dominion.


\(^\text{112}\) Regional transmission planning entities would be empowered “to make specific project recommendations at the end of the planning process and to enter binding, near-juridical findings of fact and conclusions related to the need and economic benefits of specific projects or solutions.” San Diego Gas & Electric at 6.

given to how various project proposals could be modified, combined, or eliminated so as to make the best possible use of available transmission corridors, minimize adverse environmental impacts, and enhance overarching system efficiencies.  

108. Pioneer Transmission states that it has a unique perspective on interregional transmission planning issues, as it spent the last year and a half working with the Midwest ISO and PJM in an effort to develop extra high voltage transmission facilities that will be located in both the Midwest ISO and PJM footprints. Pioneer Transmission states that although the Midwest ISO and PJM have undertaken various studies and have worked cooperatively with Pioneer Transmission, they have been hampered in their efforts to assess the Pioneer project for inclusion in their transmission plans because neither RTO has in place formal procedures for evaluating interregional projects.  

109. The Ohio Commission states in its comments that “[j]ust as the development of RTOs and ISOs was encouraged to better coordinate individual transmission owners’ and operators’ plans, the development of inter-regional planning committees to review and coordinate individual and RTO and ISO plans should be encouraged.” The California ISO states that it would be easier to analyze and justify transmission facilities that would be located in more than one region if the underlying data were consistent in all of the areas that are part of evaluating the transmission project in question.  

114 San Diego Gas & Electric at 5.  
115 Pioneer Transmission at 1-2.  
116 Ohio Commission Comments at 6.  
117 California ISO at 8.
Interest Organizations & Renewable Energy Groups state that the Commission should require coordinated transmission infrastructure plan development by regional or interregional transmission planning authorities informed by interconnection-wide assessments and broad stakeholder input.

110. The October 2009 Notice also recognized that proposals to implement interconnectionwide transmission planning were being developed in response to the above-noted funding opportunities that DOE offered under the American Recovery and Reinvestment Act of 2009. The October 2009 Notice observed that it was not clear whether those activities would result in a regular process for jointly identifying and evaluating alternatives to solutions identified in transmission plans developed through existing transmission planning processes conducted in accordance with Order No. 890.\textsuperscript{118}

111. In response to the October 2009 Notice, some commenters state that interconnectionwide transmission planning undertaken pursuant to the ARRA should be given a chance to mature before the Commission takes additional action with respect to transmission planning.\textsuperscript{119} Other commenters emphasize that funding under the ARRA is an important one-time opportunity, but should not be viewed as a prerequisite for initiating or expanding upon other transmission planning efforts.\textsuperscript{120} For example, Exelon states that the ARRA-funded transmission planning for the Eastern Interconnection is a

\textsuperscript{118} October 2009 Notice at 2-3.

\textsuperscript{119} I.e., ColumbiaGrid, NARUC, New England States’ Committee on Electricity, and Organization of MISO States.

\textsuperscript{120} I.e., Eastern Interconnection Planning Collaborative Analysis Team, Entergy, and Progress Energy.
positive effort, but is aimed at evaluating what would happen under various scenarios rather than at evaluating solutions and identifying the best solution for any given transmission planning problem. AWEA states that the Commission should not rely on interconnectionwide transmission planning undertaken pursuant to the ARRA as the sole means for reforming the transmission planning process because the ARRA-funded efforts cannot be expected to lead to the near-term changes that need to be implemented in order to support development of renewable energy resources.

112. The Commission supports and encourages the interconnectionwide transmission planning efforts being undertaken pursuant to the ARRA. As noted above, broad participation in sessions to date related to these efforts suggests that that the availability of federal funds to pursue interconnectionwide transmission planning has increased awareness of the potential for greater coordination among regions in transmission planning. The Commission anticipates that the ARRA-funded efforts will enhance transmission planning by, among other actions, building upon local and regional transmission planning processes and improving capabilities to model the development of transmission enhancements for the various scenarios of interest to state and federal policy makers and other stakeholders, as well as Canadian provincial policy makers in the Western Interconnection. We emphasize that this Proposed Rule, which does not require interconnectionwide planning or cost allocation, is not intended to interfere with the efforts already underway in ARRA-funded transmission planning initiatives.

113. However, even with these important steps toward interconnection-wide scenario analysis, the Commission remains concerned that the lack of coordinated transmission
planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers. These circumstances may result in transmission rates that are unjust and unreasonable. Therefore, the Commission proposes reforms that are intended to improve coordination between neighboring transmission planning regions with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that could address transmission needs more efficiently than separate intraregional facilities.

2. **Proposed Interregional Planning Reforms**

114. We propose to require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to address transmission planning issues, as discussed below.\(^\text{121}\) This coordination between transmission planning regions must be reflected in an interregional transmission planning agreement to be filed with the Commission.

115. The interregional transmission planning agreement may be developed on behalf of the public utility transmission providers within multiple transmission planning regions. For example, two RTOs may set forth the requirements of their interregional transmission planning coordination as part of an overall joint operating agreement between them. A public utility transmission provider that is not in an RTO or ISO may, for example, work

\(^{121}\) This proposal does not require a public utility transmission provider to enter into an interregional transmission planning agreement with a neighboring transmission planning region in another interconnection.
with other transmission providers that participate in its regional transmission planning process to create and enter into a multilateral interregional transmission planning agreement with transmission providers in a neighboring transmission planning region. Although not required under this proposal, we encourage public utility transmission providers to explore possible multilateral interregional transmission planning agreements among several, or even all, regions within an interconnection, building on processes developed through the ARRA-funded transmission planning initiatives. We note that multilateral interregional transmission planning agreements may minimize the growing number of planning meetings that some stakeholders suggest pose barriers to their meaningful participation in the planning processes, given their limited resources.

116. The interregional transmission planning agreement must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that are not proposed but that could address transmission needs more efficiently than separate intraregional facilities.

117. While the Commission encourages every interregional transmission planning agreement to be tailored to best fit the needs of the regions entering into the agreement, there are certain elements that we propose each public utility transmission provider must ensure are included in any interregional transmission planning agreement in which it participates. Including these elements will help to ensure a proactive, comprehensive process. Specifically, we propose that an interregional transmission planning agreement
must include: (1) a commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities; (2) an agreement to exchange at least annually planning data and information; (3) a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both regions; and (4) a commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

118. With respect to the third proposed requirement for an interregional transmission planning agreement, the Commission proposes that the sponsor of a project that would be located in both transmission planning regions to which that agreement applies must first propose its project in the transmission planning process of each of those transmission planning regions. The Commission further proposes that such a submission would trigger a procedure established by the interregional transmission planning agreement, under which the transmission planning regions would coordinate their reviews of and jointly evaluate the proposed project. The Commission proposes that such coordination and joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed project. Finally, the Commission proposes that inclusion of the interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to application of an interregional cost allocation method that satisfies the cost allocation principles proposed below in this NOPR.
119. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule, including the proposed required elements of an interregional transmission planning agreement and any other elements that should be part of an interregional transmission planning agreement. In particular, we seek comment on how such an agreement would be implemented in non-RTO or ISO regions and on the impact that an interregional transmission planning agreement would likely have on the development of interregional transmission facilities.

120. We recognize that development of interregional transmission planning agreements would take time and would necessarily depend on progress at the regional level. Accordingly, the Commission proposes to require the interregional transmission planning agreements to be submitted to the Commission no later than one year after the effective date of the final rule issued in this proceeding.

V. Proposed Reforms: Cost Allocation

A. Introduction


121. In Order No. 890, the Commission found that there is a close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan. The Commission stated that knowing how the costs of new transmission facilities would be allocated is critical to the development of new infrastructure, because transmission providers and customers cannot
be expected to support the construction of new transmission unless they understand who
will pay the associated costs.\(^{122}\)

122. In light of this close relationship, the Commission included a principle entitled
“Cost Allocation for New Projects” among the Order No. 890 transmission planning
principles. The Commission stated that the Order No. 890 Cost Allocation principle was
intended to apply to projects that did not fit under existing cost allocation methods. As
examples of such projects, the Commission cited regional projects involving several
transmission owners and economic projects that are identified pursuant to the Order
No. 890 economic planning studies principle for transmission planning, rather than
through individual requests for transmission service.\(^{123}\)

123. The Commission did not impose a particular cost allocation method in Order
No. 890, but instead permitted public utility transmission providers, customers, and other
stakeholders to determine a method that would be appropriate given the needs of the
region. While allowing this flexibility among regions, the Commission also stated that
providing some overall guidance on the issue was appropriate. The Commission stated
that when considering a dispute over cost allocation, it would exercise its judgment by
weighing several factors. First, the Commission stated that it would consider whether a
cost allocation proposal fairly assigns costs among participants, including those who
cause the costs to be incurred and those that otherwise benefit from them. Second, the

\(^{122}\) Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

\(^{123}\) Id. P 558.
Commission stated that it would consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, the Commission stated that it would consider whether the proposal is generally supported by state authorities and participants across the region.\(^\text{124}\)

124. The Commission also stated that these factors are particularly important as applied to economic projects that are identified pursuant to the Order No. 890 economic planning studies principle for transmission planning, such as upgrades to reduce congestion or enable groups of customers to access new generation. The Commission stated that, as a general matter, the beneficiaries of any such project should agree to support its costs. The Commission recognized, however, that there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefit from it. The Commission also stated that a range of solutions to free rider problems is available, noting that different regions have attempted to address those problems in a variety of ways.\(^\text{125}\)

125. To comply with the cost allocation principle, the Commission directed each public utility transmission provider to clearly define the details of its cost allocation method as part of a new attachment to its OATT. The Commission stated that each proposal should identify the types of new projects that are not covered under previously existing cost

\(^{124}\) Id. P 559.

\(^{125}\) Id. P 561 ("[D]ifferent regions have attempted to address such issues in a variety of ways, such as by assigning transmission rights only to those who financially support a project or spreading a portion of the cost of certain high-voltage projects more broadly than the immediate beneficiary/supporters of the project.").
allocation methods and, therefore, would be affected by the Order No. 890 cost allocation principle. The Commission also stated that it is important that each region address these cost allocation issues up front, at least in principle, rather than having them relitigated each time a project is proposed. The Commission explained that up-front identification of how the cost of a facility will be allocated will allow transmission providers, customers, and potential investors to make the decision whether or not to build that facility on an informed basis.

126. After several rounds of compliance filings, the Commission approved various public utility transmission providers’ proposals pursuant to the cost allocation principle. The Commission found that the proposals adequately identified both the types of new projects that were not covered under previously existing cost allocation methods and new methods for allocating the cost of those projects.

127. Particularly in transmission planning regions outside of the RTO and ISO footprints, many of the cost allocation methods that the Commission accepted in the Order No. 890 compliance proceedings rely exclusively on a “participant funding” approach to cost allocation. Under a participant funding approach to cost allocation, the

126 Id. P 558.
127 Id. P 561.
128 Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 251. The Commission also stated that neither adoption of a cost allocation method nor identification of an upgrade (whether driven by reliability or economics) in a transmission plan triggers an obligation to build. Id.
costs of a new transmission facility are allocated only to entities that volunteer to bear those costs.

128. For example, El Paso Electric proposed in its Order No. 890 compliance filing to use a cost allocation method in which such entities would share the costs proportionally based on each participant’s desired use of the facility to be constructed. Other members of WestConnect, such as Public Service Company of Colorado, filed and now use similar participant funding cost allocation methods. South Carolina Electric & Gas included in its Order No. 890 compliance filing the Southeast Inter-Regional Participation Process (SIRPP) provisions stating that costs for economics-driven upgrades will be born entirely by the transmission owner that builds the facilities. Similarly, Entergy filed and had approved a method where the costs for projects developed under its Regional Planning Process and its interregional transmission planning process would be born by the party that constructs the facilities. ColumbiaGrid and the Northern Tier Transmission Group both utilize a study committee process whereby alternative cost allocation methods can be proposed for projects within their respective regions. However, both ColumbiaGrid and Northern Tier

131 South Carolina Electric & Gas Company, 127 FERC ¶ 61,275, at P 50 (2009).
Transmission Group use a process where, if no agreement on cost allocation among the study team participants or the project proponents is obtained, the entities requesting the project will bear the costs.

2. **October 2009 Notice and Subsequent Comments**

129. As discussed above, in the October 2009 Notice, the Commission posed a number of questions with respect to allocating the cost of transmission facilities. Those questions drew wide-ranging responses as to whether further Commission action on cost allocation is needed at this time and, if so, what that action should be.

130. Among the commenters, there is general agreement that the Commission should not supersede existing, ongoing processes in various parts of the country that are attempting to address regional and interregional cost allocation issues.

131. Nonetheless, commenters supporting further Commission action on cost allocation at this time generally assert that the Commission should provide more detailed guidelines or principles for allocating the costs of new transmission facilities.\(^{134}\) Many commenters argue that a clear path to cost recovery is necessary for a new transmission project to move beyond the evaluation stage and to be included in any regional transmission planning process and ultimately to proceed to construction.\(^{135}\) Such commenters indicate that risks associated with cost recovery—together with the risks associated with

\(^{134}\) *E.g.*, APPA, National Rural Electric Coops, Transmission Access Policy Study Group, Transmission Dependent Utility Systems, and California ISO.

\(^{135}\) *E.g.*, American Transmission, AWEA, E.ON Climate & Renewables North America, Energy Future Coalition, and NextEra.
permitting and siting—are among the most significant obstacles to the construction of a new transmission facility, especially if customers that are allocated costs do not perceive that they will benefit from the proposed facility.\textsuperscript{136} Old Dominion emphasizes that many of the obstacles inhibiting transmission development are interrelated, but that greater certainty on cost allocation would likely ease access to capital for proposed facilities.\textsuperscript{137} 132. Several commenters specifically address cost allocation as an impediment to the development of generation to satisfy renewable portfolio standards implemented by the states.\textsuperscript{138} AWEA, for example, states that cost allocation policies are the biggest impediment to construction of new transmission facilities, regardless of location, and that costs should be assigned to all entities that benefit from a new facility. AWEA further comments that a participant funding cost allocation method does not achieve that goal.\textsuperscript{139} These commenters also state that uncertainty over cost allocation imposes significant costs on customers attempting to export energy from renewable resources and inhibit planning for the integration of the most economic generation resources into the transmission grid. Maine PUC and Public Advocate state that the existing ISO-NE cost

\textsuperscript{136} E.g., AWEA, Transmission Dependent Utility Systems, Xcel, Transmission Access Policy Study Group, and National Rural Electric Coops.

\textsuperscript{137} Old Dominion at 26.

\textsuperscript{138} E.g., AWEA at 9-10, American Transmission and Exelon.

\textsuperscript{139} AWEA at 4. \textit{See also} Transmission Access Policy Study Group at 25-27.
allocation methods are not optimal when considering large amounts of wind integration.\textsuperscript{140}

133. Similarly, the majority of commenters that address cost allocation for large, interregional transmission facilities agree that the Commission should provide more guidance on cost allocation.\textsuperscript{141} Some commenters complain that as a general matter, the Commission has addressed cost allocation methods only for facilities within the footprint of a single transmission provider or a single RTO or ISO, and not for interregional projects. For example, AEP states that it has experienced delays in developing transmission facilities that cross RTO boundaries as a result of uncertainty over cost allocation, as well as difficulties with how the facilities are to be planned.

134. Some of these commenters assert that the expansion of regional power markets and the increasing adoption by state governments of renewable energy requirements have led to a growing need for new transmission facilities that cross several utility and/or RTO or ISO regions. These commenters generally support, or state that they do not oppose, the Commission establishing a process to help stakeholders address cost allocation matters over larger geographic areas. For example, California ISO and the California Commission comment that, although cost allocation within the California ISO works well, they support the Commission creating a process to consider cost allocation over a larger region in the West.

\textsuperscript{140} Maine PUC and Public Advocate at 7-8.
\textsuperscript{141} \textit{E.g.,} AEP, ITC Holdings, and Exelon.
135. In addition, the comments in response to the October 2009 Notice reflect a general consensus that those who share in the benefits of transmission projects should also share in their costs. However, there is no consensus on what types of benefits should be considered or how such benefits should be calculated. Certain commenters, for example, support recognition of a broad spectrum of benefits that may stem from transmission development, such as environmental impacts, land conservation and energy security.\footnote{E.g., AEP, AWEA, Baltimore Gas and Electric, Energy Future Coalition, Green Energy Express, ITC Holdings, MidAmerican, National Audubon Society, NextEra, and Public Interest Organizations & Renewable Energy Groups.} Other commenters urge the Commission to avoid a uniform approach to determining the benefits of transmission projects.\footnote{E.g., ColumbiaGrid, ConEd, Delaware Municipal and Southwestern Electric, and Northeast Utilities.}

136. Several commenters suggest that if the Commission decides to establish a default cost allocation method for new transmission facilities, such a method should be employed and enforced only when stakeholders are unable to agree upon their own regional cost allocation method or methods.\footnote{E.g., American Transmission, National Grid, Northern Tier Transmission Group, and NEPOOL Participants.} For example, American Transmission, National Grid, Northern Tier Transmission Group, and NEPOOL Participants state that the Commission could create a generic cost allocation method as a backstop, which would apply when parties or regions could not come to their own agreement. Other commenters express the
view that the Commission should create one or more rebuttable presumptions about who benefits from various types of facilities in order to make cost allocation easier. 145

137. Finally, many commenters state that no further generic Commission action on cost allocation is needed at this time because the processes in their own regions already address, or are now working to address, cost allocation. For example, in the Southeast, some commenters state that their processes for cost allocation are working well and argue that the Commission should continue to allow regional flexibility on cost allocation processes. 146 Similarly, in the West, some commenters state that cost allocation in their region is not a problem. 147

B. **Legal Authority and Need for Reform**

138. Based on the comments received in response to the October 2009 Notice, the Commission believes that further reform with respect to transmission cost allocation methods may be necessary in order to ensure that the rates, terms and conditions of transmission service in interstate commerce are just and reasonable and not unduly discriminatory or preferential.

1. **The Cost Causation Principle**

139. Under sections 205 and 206 of the FPA, the Commission is responsible for ensuring that the rates, terms, and conditions for transmission of electricity in interstate

---

145 *E.g.*, ITC Holdings, MidAmerican, PJM, Solar Energy Industries, and WIRES.

146 *E.g.*, Entergy, Southern Companies, and Florida Transmission Providers.

147 *E.g.*, ColumbiaGrid, Northern Tier Transmission Group, Transmission Agency of Northern California, Salt River Project and WestConnect Planning Parties.
commerce are just, reasonable, and not unduly discriminatory or preferential.\textsuperscript{148} With respect to this responsibility, the Commission and the courts have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the “cost causation” principle.

140. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has defined the cost causation principle as follows: “[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.”\textsuperscript{149} The U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) recently quoted and elaborated on that definition, stating, “All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.”\textsuperscript{150}

\textsuperscript{148}16 U.S.C. 824d, 824e.

\textsuperscript{149}K N Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (K N Energy).

The Commission has frequently made similar statements with respect to the cost causation principle. For example, as noted above, the Commission stated in Order No. 890 that one factor it weighs when considering a dispute over cost allocation is whether a cost allocation proposal fairly assigns costs among participants, including those who cause the costs to be incurred and those that otherwise benefit from them.\footnote{Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.}

141. In applying the cost causation principle, the Commission has generally allocated costs to beneficiaries that have entered a voluntary arrangement with the public utility that is seeking to recover those costs. One example of a voluntary cost recovery arrangement with a public utility is voluntary membership in an RTO or ISO that makes an entity subject to the cost allocation provisions of the RTO’s or ISO’s tariff.\footnote{The Commission notes that RTO or ISO membership does not eliminate the need to satisfy the other aspects of the cost causation principle that are discussed above.} The Commission also has permitted joint-ownership agreements where the owners share the costs of the new transmission facilities.

142. The cost causation principle, however, is not limited to voluntary arrangements. Indeed, if the Commission were limited to allocating costs only to beneficiaries that voluntarily accept those costs, then the Commission could not fulfill its responsibilities under the FPA. If the Commission could not address free rider problems associated with new transmission investment, then it could not ensure that transmission rates are just and reasonable and not unduly discriminatory. The cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise
benefit from them, as the Commission also recognized in Order No. 890. In other words, the Commission may determine that an entity’s status as a beneficiary of a transmission facility identified through an appropriate process is relevant for purposes of applying the cost causation principle, even if that beneficiary has not entered a voluntary arrangement with (e.g., as a customer of) the public utility that is seeking to recover the costs of that facility.

143. The Commission has expressed a willingness to make such a determination. For example, when presented with concerns about parallel path flow,\(^{153}\) the Commission has offered repeatedly that if a public utility can demonstrate that a transaction is a burden on its system, then that utility can propose a transmission service rate for Commission consideration that would account for the unauthorized use of its system.\(^{154}\) The Commission has cautioned against the hasty submittal of such unilateral filings, describing its general policy as expecting owners and controllers of transmission facilities

\(^{153}\) The Commission has described the phenomenon of parallel path flow as follows: “In general, utilities transact with one another based on a contract path concept. For pricing purposes, parties assume that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. However, in reality power flows are rarely confined to a designated contract path. Rather, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being transmitted from one utility to another to travel along multiple parallel paths and divide itself along the lines of least resistance. This parallel path flow is sometimes called ‘loop flow.’” *Indiana Michigan Power Co. and Ohio Power Co.*, 64 FERC ¶ 61,184, at 62,545 (1993).

to attempt to resolve parallel path flow issues on a consensual, regional basis.  

Nonetheless, if approved by the Commission, such a proposal to address parallel path flow would allow a public utility to recover costs from a beneficiary of its system in the absence of a voluntary arrangement between the utility and that beneficiary.

144. The Commission also affirmatively required costs of transmission facilities to be allocated to beneficiaries in the absence of a voluntary arrangement in a series of orders involving the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM Interconnection, L.L.C. (PJM). Specifically, the Commission directed Midwest ISO and PJM to develop cost allocation methods for new facilities in one of their footprints that benefit entities in the other’s footprint.  

Echoing precedent applying the cost causation principle, the Commission later conditionally accepted a proposal that Midwest ISO and PJM submitted in compliance with that directive on the grounds that it “more accurately identifies the beneficiaries and allocates the associated costs” than did the cost allocation methods that were previously in place.

__________________________

155 Id. See also Southern California Edison Co., 70 FERC ¶ 61,087, at 61,241-42 (1995).


145. These examples show that the Commission has asserted its authority to allocate the costs of jurisdictional facilities to beneficiaries whether or not those beneficiaries have entered into a voluntary agreement with the public utility that is seeking to recover those costs.

146. In addition, courts have affirmed that the cost causation principle allows the Commission to allocate at least some types of costs to beneficiaries that are not customers of the public utility that is seeking to recover the costs in question. For example, the D.C. Circuit addressed this issue in a case that involved a proposal for Midwest ISO to recover administrative costs through a charge that would apply to transmission loads subject to the Midwest ISO’s tariff rates: i.e., new wholesale loads and unbundled retail loads, but not bundled retail loads and loads served pursuant to grandfathered contracts.\(^{158}\)

Describing the core issue as whether the Commission’s orders comported with the cost causation principle, the D.C. Circuit found that the Commission reasonably allocated the administrative costs more broadly than Midwest ISO proposed.\(^{159}\) After stating that the subject costs were the administrative costs of having an ISO, the D.C. Circuit found that

\(^{158}\) Midwest ISO Transmission Owners, 373 F.3d 1361. The D.C. Circuit stated that the subject costs “are primarily MISO’s startup expenses – particularly those pertaining to the MISO Security Center – and certain expenses pertaining to the creation and administration of MISO’s open access tariff.” Id. at 1369.

\(^{159}\) Id. at 1370.
the Commission correctly determined that bundled and grandfathered loads should share
the cost of having an ISO because they drew benefits from Midwest ISO.\footnote{160}

147. Thus, in applying the cost causation principle, the Commission may allocate costs
of a transmission facility to a beneficiary identified through an appropriate process, such
as a Commission-approved transmission planning process, even if that beneficiary has
not entered a voluntary arrangement with the public utility that is seeking to recover the
costs of that facility. After satisfying this standard with respect to beneficiary
identification, the cost causation principle also requires the Commission to ensure that the
costs allocated to a beneficiary under a cost allocation method are at least roughly
commensurate with the benefits that are expected to accrue to that entity.\footnote{161} On this
point, the D.C. Circuit has explained that “the cost causation principle does not require
exacting precision in a ratemaking agency’s allocation decisions.”\footnote{162}

2. \textbf{Need for Reform}

148. The Commission’s responsibility under FPA sections 205 and 206 to ensure that
transmission rates are just and reasonable and not unduly discriminatory or preferential is
not new, nor is the Commission’s recognition of the cost causation principle. However,

\footnote{160} \textit{Id.} at 1370-71.

\footnote{161} \textit{Illinois Commerce Commission}, 576 F.3d at 476-77 (“We do not suggest that
the Commission has to calculate benefits to the last penny, or for that matter to the last
million or ten million or perhaps hundred million dollars.”). \textit{See also Midwest ISO
Transmission Owners}, 373 F.3d 1361 at 1369 (“we have never required a ratemaking
agency to allocate costs with exacting precision.”); \textit{Sithe}, 285 F.3d 1 at 5.

\footnote{162} \textit{Midwest ISO Transmission Owners}, 373 F.3d 1361 at 1371 (citing \textit{Sithe}, 285
F.3d 1 at 5).
the circumstances in which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, such as changes with respect to the demands placed on the transmission grid.

149. The Commission has previously recognized changes in circumstances that warranted changes in the manner by which public utilities recover transmission costs. In the early 1990s, the Commission identified “dramatic changes which the electric industry has faced, and will face in the near term,” such as “increased reliance on market forces to meet power supply needs; new market entrants such as exempt wholesale generators; a significant number of utility mergers and combinations; more highly integrated operation of various power pools; and substantial bulk power trading among electric systems,” as well as the initial filing of open access transmission tariffs.\(^{163}\) To account for those developments and the industry’s changing needs, the Commission issued a policy statement that increased flexibility with respect to transmission pricing.\(^{164}\)

150. Many of those changes have not only continued but also accelerated in recent years. For example, as commenters stated in response to the October 2009 Notice, the further expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions. The


industry’s continuing transition from relatively localized trading to larger regional power markets also results, among other effects, in broader diffusion of the benefits associated with transmission upgrades and new transmission facilities.

151. Similarly, the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of location-constrained renewable energy resources that are frequently remote from load centers, as well as a growing need for new transmission facilities that cross several utility and/or RTO or ISO regions. Transmission facilities that are needed to comply with state renewable portfolio standard measures illustrate the increasing potential for benefits associated with meeting public policy-driven transmission needs.

152. More generally, as stated above, challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. As noted above, constructing new transmission facilities requires a significant amount of capital. Therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. However, there are few rate structures in place today that provide both for analysis of the beneficiaries of a transmission facility that is proposed to be located within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region, and for corresponding allocation and recovery of the facility’s costs. The lack of such rate structures creates significant risk for transmission developers that they will have no identified group of customers from which to recover the cost of their investment. In addition, cost allocation within RTO or
ISO regions, particularly those that encompass several states, is often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair. Some comments filed in response to the October 2009 Notice present these types of concerns and state the resultant uncertainty regarding cost allocation remains an impediment to development of needed transmission facilities.

153. The risk of the free rider problems associated with new transmission investment that the Commission described in Order No. 890 is also particularly high for projects that affect multiple utilities’ transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development. On one hand, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, increases this incentive and, in turn, the likelihood that needed transmission facilities will not be constructed in a timely manner. On the other hand, if costs are allocated to entities that will receive no benefit from a transmission facility, then those entities are more likely to oppose inclusion of the facility in a regional transmission plan or to otherwise impose obstacles that delay or prevent the facility’s construction.

154. In light of these challenges and recent developments affecting the industry, the Commission is concerned that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities and, thus, may result in rates that are not just and reasonable or are unduly discriminatory or preferential.
C. Proposed Reforms

155. The Commission proposes to amend its regulations to address the concerns discussed above.

156. First, we propose to more closely align transmission planning and cost allocation processes. A transmission planning process includes a facility in a transmission plan in order to achieve a specific purpose or purposes, such as to avoid an impending violation of a Reliability Standard, reduce congestion and thereby increase access to lower-cost resources, or enable compliance with public policy requirements established by state or federal laws or regulations. Because such purposes involve the identification of expected beneficiaries—either explicitly or implicitly—establishing a closer link between transmission planning and cost allocation will address in part the Commission’s concern that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities.

157. The Commission has previously suggested that transmission planning at least on a regional basis is closely related to cost allocation. As noted above, this premise underlies the Commission’s establishment in Order No. 890 of a transmission planning principle on cost allocation for new transmission facilities. In addition, the Commission has explained that it may be appropriate to have different cost allocation methods for facilities that are planned for different purposes or pursuant to different transmission planning processes. For example, the Commission distinguished between existing facilities in Midwest ISO and PJM for which it found that license plate rates are appropriate, and new facilities in
those regions for which it approved broader cost allocation methods. The Commission found it significant that Midwest ISO and PJM plan the construction of new facilities based on each RTO’s independent transmission planning process, which helps to ensure that new projects are necessary to meet the reliability and economic needs of each RTO’s system as a whole. The Commission also noted that Midwest ISO and PJM plan certain new facilities pursuant to a joint RTO planning process under a Joint Operating Agreement. By contrast, the Commission stated that decisions to build existing facilities within Midwest ISO and PJM were not made as part of any regional planning process.

The Commission recognizes that identifying which types of benefits are relevant for cost allocation purposes, which entities are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. The Commission believes that a transparent transmission planning process is the appropriate forum to address these issues. In addition, addressing these issues through the transmission planning process would increase the likelihood that facilities included in transmission plans are actually constructed, rather than being included in a transmission plan only to later encounter cost allocation disputes that prevent their construction.

Accordingly, the Commission proposes to require that every public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities that are included in the transmission plan produced by the

---

166 Id. P 96.
transmission planning process in which it participates. If the public utility transmission provider is an RTO or ISO, then the method or methods would be required to be set forth in the RTO or ISO tariff. In other transmission planning regions, each public utility transmission provider located within the region would be required to set forth in its tariff the method or methods for cost allocation used in its transmission planning region.

160. An RTO or ISO or the public utility transmission providers in a transmission planning region may have a single cost allocation method for all new transmission facilities or different methods for different types of facilities. For example, cost allocation methods may distinguish among facilities that are driven by needs associated with maintaining reliability, relieving congestion, and achieving public policy requirements established by state or federal laws or regulations, all of which would be required to be considered in the regional transmission planning process as explained elsewhere in this Proposed Rule. The Commission recognizes that several transmission planning regions that have different cost allocation methods by type of project currently have transmission planning procedures and cost allocation methods that refer only to the first two categories of transmission projects. The Proposed Rule would permit a public utility transmission provider or transmission planning region to distinguish or not distinguish among these three types of transmission facilities, as long as each of the three is considered in the transmission planning process and there is a means for allocating the costs of each type of facility to beneficiaries.

161. Second, we propose to require that each public utility transmission provider within a transmission planning region develop a method for allocating the costs of a new
interregional transmission facility between the two neighboring transmission planning regions in which the facility is located or among the beneficiaries in the two neighboring transmission planning regions.

162. Third, to ensure that the cost allocation method or methods are just and reasonable and not unduly discriminatory or preferential, we propose to assess each cost allocation method based upon the cost allocation principles set out in the following sections, one set of principles for intraregional facilities and another for interregional facilities. To reiterate, we propose that the cost allocation method or methods be applied to new transmission facilities included in the transmission plan produced by the transmission planning process in which the public utility transmission provider participates.

163. Finally, we note that under our proposals, public utility transmission providers will have the first opportunity to develop cost allocation methods for intraregional and interregional transmission facilities in consultation with customers and other stakeholders. In the event that no agreement can be reached, the Commission would use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets the Commission’s proposed requirements.

1. **Intraregional Cost Allocation**

164. An intraregional transmission facility is defined as a transmission facility located entirely within the geographic boundaries of one transmission planning region. As proposed here, each RTO or ISO on behalf of its transmission owning members, or the individual public utility transmission providers in a non-RTO or ISO transmission planning region, would be required to demonstrate through a compliance filing that it has
a cost allocation method or methods that address cost recovery for each new transmission facility included in its regional transmission plan and that satisfy the following principles:

1. 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.\textsuperscript{167} 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 established by state or federal laws or regulations that may drive transmission needs.\textsuperscript{168}

2. Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.

3. If a benefit to cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional transmission plan for the

\textsuperscript{167} Illinois Commerce Commission, 576 F.3d at 476-77 (“We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.”). See also Midwest ISO Transmission Owners, 373 F.3d 1361 at 1369 (“we have never required a ratemaking agency to allocate costs with exacting precision.”); Sithe, 285 F.3d 1 at 5.

\textsuperscript{168} As discussed above, the Commission proposes to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.
purpose of cost allocation, it must not be so high that facilities with significant positive net benefits are excluded from cost allocation. A transmission planning region or public utility transmission provider may want to choose such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a 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 a greater ratio.

(4) The allocation method for the cost of an intraregional facility must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if there is an agreement for the original region to bear costs associated with such upgrades, then the original region’s cost allocation method or methods must include provisions for allocating the costs of the upgrades among the entities in the original region.

(5) 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.

(6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.

165. In proposing these principles, the Commission does not intend to prescribe a uniform approach to cost allocation for new intraregional transmission facilities. To the contrary, we recognize that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. Therefore, this Proposed Rule would allow the public utility transmission providers in each transmission planning region to develop a transmission cost allocation method that best suits the needs of that transmission planning region.

166. However, the Commission proposes that, if the public utility transmission providers in a transmission planning region, in consultation with customers and other stakeholders, cannot agree on a cost allocation method for new intraregional transmission facilities that satisfies these principles, the Commission would use the record in the relevant compliance filing proceeding as a basis for applying these principles to develop
a cost allocation method that meets the Commission’s requirements. Consistent with the Commission’s intention not to prescribe a uniform approach, this cost allocation method would not necessarily be the same for every transmission planning region where the public utility transmission providers are unable to agree on a cost allocation method that satisfies the principles.

167. The Commission recognizes that several approaches to cost allocation may satisfy the proposed principles. For example, a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a facility or class or group of facilities (e.g., all transmission facilities at 345 kV or higher), especially if the distribution of benefits associated with a class or group of facilities is likely to vary considerably over the long depreciation life of the facilities amid changing power flows, fuel prices, population patterns, and local economic developments. Similarly, other methods that propose cost allocation to a narrower class of beneficiaries may be appropriate, provided that the method reflects an evaluation of beneficiaries and is adequately defined and supported by the transmission planning region.

168. In addition, the principles proposed in this rulemaking do not foreclose the opportunity for a transmission developer or individual customer to voluntarily assume the costs of a new transmission facility. In other words, the proposed principles would not prohibit voluntary participant funding. However, if a transmission developer believes that others in the transmission planning region may benefit from a new transmission facility and want to seek broader cost allocation, then that developer must be permitted to
propose its project in the regional transmission planning process that will evaluate the project’s beneficiaries. If the facility is included in the regional transmission plan, the costs of that facility must be eligible for allocation pursuant to the Commission-approved method for allocating the cost of a new transmission facility in that plan.\textsuperscript{170} As stated above, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, exacerbates the free rider problem that the Commission described in Order No. 890. Such a cost allocation method would not satisfy the proposed principles.

169. With regard to a new transmission facility that is located entirely within one transmission owner’s service territory, a transmission owner may not unilaterally invoke the regional cost allocation method to require the allocation of the costs of a new transmission facility to other entities in its transmission planning region. However, if the regional transmission planning process determines that a new facility located solely within a transmission owner’s service territory would provide benefits to others in the region, allocating the facility’s costs according to that region’s intraregional cost allocation method would be permitted.

2. \textbf{Interregional Cost Allocation}

170. An interregional transmission facility is one that in located within two or more transmission planning regions. In the past, most transmission upgrades were planned and

\textsuperscript{170} However, certain transmission developers may seek to participate in the regional transmission planning process only for coordination purposes (e.g., to perform a reliability check for a participant-funded or merchant transmission project), in which case the transmission plan would not include a cost allocation for such projects.
constructed to meet the needs of customers within a given transmission planning region. However, new transmission facilities located within multiple transmission planning regions are now being considered by transmission providers in various parts of the nation. For example, as discussed above, development of renewable energy resources is increasing rapidly, in part in response to state renewable portfolio standard requirements. However, many of these resources are located far from load centers. New transmission facilities located within multiple transmission planning regions may be necessary to deliver the output of these renewable energy resources.

171. There are few rate structures in place today that provide for the allocation and recovery of costs of interregional transmission facilities. We are concerned that the absence of clear cost allocation rules for interregional transmission facilities could impede the development of such facilities, because of uncertainty regarding recovery of associated costs. In addition, the combined size of the multiple transmission planning regions in which an interregional facility would be located may increase the potential for both free ridership and the allocation of costs to those that receive no benefit from a facility.

172. Therefore, we propose to require that the public utility transmission providers located in each pair of neighboring transmission planning regions develop a mutually agreeable method for allocating between the two transmission planning regions the costs of a new transmission facility that is located within both regions and that is eligible for interregional cost recovery pursuant to the region’s interregional transmission planning agreement developed in accordance with the requirement proposed above. In an RTO or
ISO region, we propose that the method must be filed to become a part of the relevant tariffs. In other transmission planning regions, we propose that the cost allocation method be filed as part of the OATT of each public utility transmission provider in the region.

173. A group of three or more transmission planning regions within an interconnection—or all of the transmission planning regions within an interconnection—may agree on and file a common method for allocating the costs of a new interregional transmission facility. However, the Commission does not propose to require such agreements among more than two neighboring transmission planning regions.

174. Each cost allocation method filed in accordance with this proposal would be required to comply with the following principles:

(1) The costs of a new interregional facility must be allocated to each transmission planning region in which that facility is located in a manner that is at least roughly commensurate with the estimated benefits of that facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.\(^\text{171}\)

\(^{171}\) As discussed above, the Commission proposes to require each public utility (continued)
(2) A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that facility.

(3) If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold, may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.

(4) Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located. However, the interregional planning process transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.

For example, a DC line that runs from a first transmission planning region, through a second transmission planning region, and into a third transmission planning region, with no tap in the second region, may not provide any benefits to the second region.
must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if there is an agreement among the transmission providers in the regions in which the facility is located to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of the upgrades within the transmission planning regions in which the facility is located.

(5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

(6) The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out and explained in detail in the compliance filing for this rule.

175. As with intraregional cost allocation, we are not proposing to require a uniform method of cost allocation for interregional transmission facilities. There may be legitimate reasons for the public utility transmission providers located in neighboring transmission planning regions to adopt different cost allocation methods. The
Commission recognizes that several approaches to cost allocation may satisfy the proposed principles.¹⁷³

176. Therefore, we propose to allow methods for allocating the costs of new interregional facilities to differ among pairs of transmission planning regions, as long as each method satisfies the proposed interregional cost allocation principles listed above. Moreover, the method used for allocating interregional transmission facility costs between any two transmission planning regions may be different from the method used by the public utility transmission providers located in either of those transmission planning regions to allocate the costs of new intraregional facilities. In addition, the cost allocation method used by the public utility transmission providers located in a transmission planning region to allocate the costs of new intraregional facilities could be different from the cost allocation method by which the public utility transmission providers in the same transmission planning region further allocate costs to be borne by that transmission planning region pursuant to an agreed-upon method for allocating the costs of interregional facilities.

177. Similar to our proposal for intraregional transmission facilities, we propose that if the public utility transmission providers in coordination with their customers and other stakeholders in a pair of neighboring transmission planning regions cannot agree on a

¹⁷³ For the reasons discussed above with respect to cost allocation for intraregional transmission facilities, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, would not satisfy the proposed principles for interregional cost allocation.
cost allocation method for new interregional transmission facilities that satisfies these principles, then the Commission would use the record in the relevant compliance filing proceedings as a basis for applying the principles to develop an interregional cost allocation method that meets the Commission’s requirements. Such a cost allocation method would not necessarily be the same for every pair of neighboring transmission planning regions that is unable to agree on a cost allocation method that satisfies the principles.

178. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule. In particular, we seek comment on the appropriateness and application of the proposed cost allocation principles with respect to new intraregional and interregional transmission facilities. If commenters believe that additional principles should apply to cost allocation for either intraregional or interregional transmission facilities, the Commission asks commenters to submit and explain the need for those principles.

VI. Compliance Filings

179. The Commission proposes that each public utility transmission provider must comply with the requirements of this Proposed Rule. With the exception of the proposed requirements with respect to interregional transmission planning agreements and an interregional cost allocation method or methods, the Commission proposes to require each public utility transmission provider to submit a compliance filing within six months of the effective date of the final rule in this proceeding revising its OATT or other document(s) subject to the Commission’s jurisdiction as necessary to demonstrate that it
meets the proposed requirements set forth in this Proposed Rule. The Commission proposes to require each public utility transmission provider to submit a compliance filing within one year of the effective date of the final rule in this proceeding to demonstrate that it meets the proposed requirements set forth in the Proposed Rule with respect to interregional transmission planning agreements. The Commission proposes to require each public utility transmission provider to submit a compliance filing within one year of the effective date of the final rule in this proceeding revising its OATT as necessary to demonstrate that it meets the proposed requirements set forth in this Proposed Rule with respect to an interregional cost allocation method or methods.

180. The Commission would assess whether each compliance filing satisfies the proposed requirements and principles stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of this Proposed Rule.

181. The Commission proposes that transmission providers that are not public utilities would have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.

---

174 See Appendix B for the proposed pro forma Attachment K consistent with this NOPR.

175 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.
VII. **Information Collection Statement**

182. The following collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.\(^{176}\) OMB’s regulations require approval of certain information collection requirements imposed by agency rules.\(^{177}\) The Commission solicits comments on the Commission’s need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents’ burden, including the use of automated information techniques.

**Burden Estimate:** The estimated public reporting burdens for the proposed reporting requirements are as follows.

<table>
<thead>
<tr>
<th>FERC-917 - Proposed Reporting Requirements in RM10-23</th>
<th>Annual Number of Respondent(s) (Filers)</th>
<th>Annual Number of Responses</th>
<th>Hours per Response</th>
<th>Total Annual Hours in Year 1</th>
<th>Total Annual Hours in Subsequent Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>participation in a transparent and open intraregional transmission planning process that meets transmission planning principles, includes consideration of public policy requirements, identifies and evaluates facilities to meet needs, develops cost allocation method, and produces an intraregional transmission plan that</td>
<td>134</td>
<td>134</td>
<td>100 hrs in Year 1; 50 hrs. in subsequent years</td>
<td>13400</td>
<td>6700</td>
</tr>
</tbody>
</table>

\(^{176}\) 44 U.S.C. 3507(d).

\(^{177}\) 5 CFR 1320.11.
describes and incorporates a cost allocation method that meets the Commission's principles.

| Coordination, development, and filing with the Commission of interregional planning agreements that meet the Commission’s requirements, that include consideration of public policy requirements, and that incorporate cost allocation methods that meet the Commission's principles; provide or post ongoing communications, and provide annual data exchange. | 134 | 134 | 125 hrs. in Year 1; 50 hrs. in subsequent years | 16750 | 6700 |

| Conforming tariff changes for local transmission planning, including those related to consideration of public policy requirements; and conforming tariff changes for intraregional and interregional planning. | 134 | 134 | 50 hrs. in Year 1; 25 hours in subsequent years | 6700 | 3350 |

| **Total Estimated Additional Burden Hours, Proposed for FERC-917 in NOPR in RM10-23** | | | | 36850 | 16750 |

**Cost to Comply:** The Commission has projected costs of compliance for the reporting requirements as follows:

Year 1: $4,200,900 [36,850 hours X $114 per hour]

Subsequent Years: $1,909,500 [or 16,750 hours X $114 per hour]

OMB’s regulations require it to approve certain information collection requirements

---

The estimated cost of $114 an hour is the average of the hourly costs of: attorney ($200), consultant ($150), technical ($80), and administrative support ($25).
imposed by an agency rule. The Commission is submitting notification of this Proposed Rule to OMB. The Commission proposes to make the reporting requirements mandatory.

Title: FERC-917

Action: Proposed Collection.

OMB Control No. 1902-0233

Respondents: Electric Utility Transmission Providers. RTOs and ISOs also may file some materials on behalf of their members.

Frequency of responses: Initial filing and subsequent filings.

Necessity of the Information:

183. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission is proposing amendments to the pro forma OATT to correct certain deficiencies in transmission planning and cost allocation requirements for public utility transmission providers. The purpose of this proposed rulemaking is to strengthen the pro forma OATT, so that the transmission grid can better support wholesale power markets and ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. We propose to achieve this goal by reforming electric transmission planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

184. Internal Review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission’s need for efficient information collection, communication, and
management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support associated with the information requirements.

185. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873. For submitting comments concerning the collection of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Please reference OMB Control No. 1902-0233 and the docket number of this proposed rulemaking in your submission.

VIII. Environmental Analysis

186. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.\(^{179}\) The Commission concludes that neither an Environmental [179] Regulations Implementing the National Environmental Policy Act, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).
Assessment nor an Environmental Impact Statement is required for this Proposed Rule under section 380.4(a)(15) of the Commission’s regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission’s jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.  

IX. **Regulatory Flexibility Act Analysis**

187. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This Proposed Rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889 and 890. The total estimated number of public utility transmission providers that, absent waiver, would have to modify their current OATTs by filing the revised pro forma OATT is 134. Of these public utility transmission providers, an estimated 10 filers, or 7.3% percent, have output of four million MWh or less per year. The Commission does not consider this a substantial

---

182 A firm is “small” if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. Based on the filers of the annual FERC Form 1 and Form 1-F, as well as the number of companies that have obtained waivers, we estimate that 7.3% of the filers are “small.”
number and, in any event, each of these entities retains its rights to waiver of these requirements. The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889 and 890. Accordingly, the Commission certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities.

X. Comment Procedures

188. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 60 days from publication in the FEDERAL REGISTER. Comments must refer to Docket No. RM10-23-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

189. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

190. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE, Washington, DC 20426.
191. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

XI. Document Availability

192. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

193. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

194. User assistance is available for eLibrary and the FERC’s web site during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.
List of subjects in 18 CFR Part 35

Electric power rates
Electric utilities
Reporting and recordkeeping requirements

By direction of the Commission. Commissioner Moeller is concurring with a separate statement attached.

(SEAL)

Nathaniel J. Davis, Sr.,
Deputy Secretary.
In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for part 35 continues to read as follows:


2. Amend § 35.28 as follows:

   a. Paragraph (c)(1) through (c)(1)(iii) are revised.
   b. Paragraph (c)(1)(vi) is revised.
   c. Paragraphs (c)(3), (c)(3)(i), and (c)(3)(ii) are revised.
   d. Paragraphs (c)(4) through (c)(4)(ii) are revised.
   e. Paragraph (d) (1) is revised.
   f. Paragraph (e)(1) is revised.

§ 35.28 Non-discriminatory open access transmission tariff.

   (c) Non-discriminatory open access transmission tariffs.

   (1) Every public utility that owns, controls, or operates facilities used for the
transmission of electric energy in interstate commerce must have on file with the
Commission a tariff of general applicability for transmission services, including ancillary
services, over such facilities. Such tariff must be the open access pro forma tariff
contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access
and Stranded Costs), as revised by the open access pro forma tariff contained in Order
No. 890, FERC Stats. & Regs. ¶ 31,241 (Final Rule on Open Access Reforms) and
further revised in Order No. ______, FERC Stats. & Regs. ¶ ______ (Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities), or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs ¶ 31,306, Order No. 890, FERC Stats. & Regs. ¶ 32,241, and Order No. ______, FERC Stats. & Regs. ¶ ______.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. ______, FERC Stats. & Regs. ¶ ______, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], it must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, as amended by Order No.______, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. ______, FERC Stats. & Regs ¶ ____.

(iii) If a public utility owns, controls, or operates transmission facilities used for
the transmission of electric energy in interstate commerce as of [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. ______, FERC Stats. & Regs. ¶ ______, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

* * * * *

(vi) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. ______, FERC Stats. & Regs. ¶ ______, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. ______, FERC Stats. & Regs. ¶ ______.

* * * * *

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the
pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. ______, FERC Stats. & Regs. ¶ ______, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. ______, FERC Stats. & Regs. ¶ ______.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff consistent with Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No.______, FERC Stats. & Regs. ¶______, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No.______, FERC Stats. & Regs ¶______. 
(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. ______, FERC Stats. & Regs. ¶ ______, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Reg. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. ______, FERC Stats. & Regs. ¶ ______.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. ______, FERC Stats. & Regs. ¶ ____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. ______, FERC Stats. & Regs. ¶ ____. 

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. ______, FERC Stats. & Regs. ¶ ______, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to
section 206 in accordance with the procedures set forth in Order No., FERC Stats. &
Regs ¶____.

(d) **Waivers.**

(1) No later than [insert date that is 60 days after date of publication of the
Final Rule in the FEDERAL REGISTER], or

*   *   *   *   *

(e) **Non-public utility procedures for tariff reciprocity compliance.**

(1) A non-public utility may submit a transmission tariff and a request for
declaratory order that its voluntary transmission tariff meets the requirements of Order
No. 888, FERC Stats. & Regs. ¶31,036, Order No. 890, FERC Stats. & Regs. ¶31,241,
and Order No. ______, FERC Stats. & Regs. ¶______.

*   *   *   *   *
Note: The following appendices will not be published in the Code of Federal Regulations.

**Appendix A: List of Short Names of Commenters on the Federal Energy Regulatory Commission’s Notice of Request for Comments on Transmission Planning Processes under Order No. 890—Docket No. AD09-8-000, October 2009**

<table>
<thead>
<tr>
<th>Short Name or Acronym</th>
<th>Commenter</th>
</tr>
</thead>
<tbody>
<tr>
<td>3M</td>
<td>3M Company, High Capacity Conductors</td>
</tr>
<tr>
<td>AEP</td>
<td>American Electric Power Service Corporation</td>
</tr>
<tr>
<td>Alabama PSC</td>
<td>Alabama Public Service Commission</td>
</tr>
<tr>
<td>Allegheny Companies</td>
<td>Allegheny Power and Trans-Allegheny Interstate Line Company</td>
</tr>
<tr>
<td>Ameren</td>
<td>Ameren Services Company</td>
</tr>
<tr>
<td>American Antitrust Institute</td>
<td>American Antitrust Institute</td>
</tr>
<tr>
<td>American Forest and Paper</td>
<td>American Forest &amp; Paper Association</td>
</tr>
<tr>
<td>American Transmission</td>
<td>American Transmission Company LLC</td>
</tr>
<tr>
<td>APPA</td>
<td>American Public Power Association</td>
</tr>
<tr>
<td>AREVA T&amp;D</td>
<td>AREVA T&amp;D Inc.</td>
</tr>
<tr>
<td>AWEA</td>
<td>American Wind Energy Association</td>
</tr>
<tr>
<td>Baltimore Gas and Electric</td>
<td>Baltimore Gas and Electric Company</td>
</tr>
<tr>
<td>Barbara Luchsinger</td>
<td>Barbara Luchsinger</td>
</tr>
<tr>
<td>Bay Area Municipal Transmission Group</td>
<td>City of Santa Clara, California; the City of Palo Alto, California; and the City of Alameda, California</td>
</tr>
<tr>
<td>Bonneville</td>
<td>Bonneville Power Administration</td>
</tr>
</tbody>
</table>
BP Energy
The Brattle Group
California ISO
CALifornians for Renewable Energy
California PUC
California State Water Project
Calvin Daniels
Chinook and Zephyr
Clean Line
Coalition to Advance Renewable Energy Through Bulk Energy Storage
ColumbiaGrid
Consolidated Edison, et al.
Dayton Power and Light
Delaware Municipal and Southwestern Electric
Dominion
Duke
Eastern Interconnection Planning

BP Energy Company
Peter Fox-Penner, Johannes Pfeifenberger, and Delphine Hou
California Independent System Operator Corporation
CALifornians for Renewable Energy, Inc.
California Public Utilities Commission
California Department of Water Resources State Water Project
Calvin Daniels
Chinook Power Transmission, LLC and Zephyr Power Transmission, LLC
Clean Line Energy Partners, LLC
Coalition to Advance Renewable Energy Through Bulk Energy Storage
ColumbiaGrid
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.
Dayton Power and Light Company
Delaware Municipal Electric Corporation, Inc. and Southwestern Electric Cooperative, Inc.
Dominion Resources Services, Inc.
Duke Energy Corporation
Eastern Interconnection Planning
<table>
<thead>
<tr>
<th><strong>Collaborative Analysis Team</strong></th>
<th>Collaborative Analysis Team</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Eastern PJM Governors</strong></td>
<td>Governors of New Jersey, Delaware, Maryland, and Virginia</td>
</tr>
<tr>
<td><strong>EEI</strong></td>
<td>Edison Electric Institute</td>
</tr>
<tr>
<td><strong>Electricity Consumers Resource Council</strong></td>
<td>Electricity Consumers Resource Council</td>
</tr>
<tr>
<td><strong>ENE (Environment Northeast)</strong></td>
<td>ENE Environment Northeast</td>
</tr>
<tr>
<td><strong>Energy Future Coalition</strong></td>
<td>Energy Future Coalition</td>
</tr>
<tr>
<td><strong>Entergy</strong></td>
<td>Entergy Services, Inc.</td>
</tr>
<tr>
<td><strong>E.ON</strong></td>
<td>E.ON U.S. LLC</td>
</tr>
<tr>
<td><strong>E.ON Climate &amp; Renewables North America</strong></td>
<td>E.ON Climate &amp; Renewables North America</td>
</tr>
<tr>
<td><strong>EPSA</strong></td>
<td>Electric Power Supply Association</td>
</tr>
<tr>
<td><strong>Exelon</strong></td>
<td>Exelon Corporation</td>
</tr>
<tr>
<td><strong>Federal Trade Commission</strong></td>
<td>Federal Trade Commission</td>
</tr>
<tr>
<td><strong>FirstEnergy</strong></td>
<td>FirstEnergy Affiliates</td>
</tr>
<tr>
<td><strong>Florida Transmission Providers</strong></td>
<td>Florida Power &amp; Light, Progress Energy Florida, Tampa Electric Company, and JEA</td>
</tr>
<tr>
<td><strong>Georgia Transmission Corporation</strong></td>
<td>Georgia Transmission Corporation</td>
</tr>
<tr>
<td><strong>Great River Energy</strong></td>
<td>Great River Energy</td>
</tr>
<tr>
<td><strong>Green Energy Express</strong></td>
<td>Green Energy Express, LLC</td>
</tr>
<tr>
<td><strong>Illinois Commission</strong></td>
<td>Illinois Commerce Commission</td>
</tr>
<tr>
<td><strong>Imperial Irrigation District</strong></td>
<td>Imperial Irrigation District (CA)</td>
</tr>
<tr>
<td><strong>Independent Power Producers</strong></td>
<td>Independent Power Producers Coalition-</td>
</tr>
</tbody>
</table>
Coalition-West

**Indicated Partners**
Green Energy Express LLC; Transmission Technology Solutions LLC; SouthWestern Power Group II, LLC; Nevada Hydro Company; LS Power Transmission, LLC; and Pattern Transmission LP

**Integrys, et al.**
Wisconsin Public Service Corporation, Upper Peninsula Power Company, and Integrys Energy Services, Inc.

**ISO New England**
ISO New England Inc.

**ITC Holdings**
ITC Holdings Corp.

**Kelson Companies**
Cottonwood Energy Company LP; Dogwood Energy LLC; and Magnolia Energy LP

**Large Public Power Council**
Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities

**Long Island Power Authority, et al.**
Long Island Power Authority, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc.

**Lorraine Fleming**
Lorraine Fleming

**LS Power**
LS Power Transmission, LLC
<p>| <strong>Maine PUC and Public Advocate</strong> | Maine Public Utilities Commission and the Maine Office of the Public Advocate |
| <strong>Massachusetts Attorney General</strong> | Massachusetts Attorney General |
| <strong>Massachusetts Departments</strong> | Massachusetts Department of Public Utilities and Massachusetts Department of Energy Resources |
| <strong>MEAG Power</strong> | MEAG Power |
| <strong>MidAmerican</strong> | MidAmerican Energy Holdings Company |
| <strong>Midwest ISO</strong> | Midwest Independent Transmission System Operator, Inc. |
| <strong>Midwest ISO Transmission Owners</strong> | Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); City of Columbia Water and Light Department (Columbia, MO); City Water, Light &amp; Power (Springfield, IL); Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power &amp; Light Company; (Minnesota Power (and its subsidiary Superior Water, L&amp;P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas &amp; Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc. |
| <strong>Modesto Irrigation District</strong> | Modesto Irrigation District |
| <strong>NARUC</strong> | National Association of Regulatory Utility Commissioners |</p>
<table>
<thead>
<tr>
<th>National Audubon Society, et al.</th>
<th>National Audubon Society; Conservation Law Foundation; Energy Future Coalition; ENE (Environment Northeast); Environmental Defense Fund; Natural Resources Defense Council; Piedmont Environmental Council; Sierra Club; Sustainable FERC Project; and Union of Concerned Scientists</th>
</tr>
</thead>
<tbody>
<tr>
<td>National Grid</td>
<td>National Grid USA</td>
</tr>
<tr>
<td>National Nuclear Security</td>
<td>National Nuclear Security</td>
</tr>
<tr>
<td>Administration Service Center</td>
<td>Administration Service Center in Albuquerque, New Mexico</td>
</tr>
<tr>
<td>National Rural Electric Coops</td>
<td>National Rural Electric Cooperative Association</td>
</tr>
<tr>
<td>NationalWind</td>
<td>NationalWind</td>
</tr>
<tr>
<td>NEPOOL Participants</td>
<td>New England Power Pool Participants Committee</td>
</tr>
<tr>
<td>Nevada Hydro</td>
<td>Nevada Hydro Company, Inc.</td>
</tr>
<tr>
<td>New England Clean Energy Council</td>
<td>New England Clean Energy Council</td>
</tr>
<tr>
<td>New England States’ Committee on Electricity</td>
<td>New England States’ Committee on Electricity</td>
</tr>
<tr>
<td>New Jersey Board</td>
<td>New Jersey Board of Public Utilities</td>
</tr>
<tr>
<td>New York PSC</td>
<td>New York State Public Service Commission</td>
</tr>
<tr>
<td>NextEra</td>
<td>NextEra Energy Resources, LLC</td>
</tr>
<tr>
<td>Northeast Utilities</td>
<td>Northeast Utilities Service Company</td>
</tr>
<tr>
<td>Northern Tier Transmission Group</td>
<td>Northern Tier Transmission Group</td>
</tr>
<tr>
<td>Northwest State Commissions and Consumer Counsel</td>
<td>Idaho Public Utilities Commission, Montana Consumer Counsel, Montana Public Service Commission, Public Utility</td>
</tr>
</tbody>
</table>
Commission of Oregon, Utah Public Service Commission, and Wyoming Public Service Commission

**NRG**
NRG Energy, Inc.

**Ohio Commission**
Public Utilities Commission of Ohio

**Old Dominion**
Old Dominion Electric Cooperative

**Organization of MISO States**
Organization of MISO States

**Pacific Gas and Electric**
Pacific Gas and Electric Company

**Pattern Transmission**
Pattern Transmission LP

**Peter C. Luchsinger M.D.**
Peter C. Luchsinger M.D.

**PHI Companies**
Pepco Holdings, Inc.; Potomac Electric and Power Company; Delmarva Power & Light Company; and Atlantic City Electric Company

**Pioneer Transmission**
Pioneer Transmission, LLC

**PJM**
PJM Interconnection, LLC

**PPL**
PPL Electric Utilities Corporation

**Progress Energy**
Progress Energy, Inc.

**PSEG Companies**
Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC

**Public Interest Organizations & Renewable Energy Groups**
Alliance for Clean Energy New York; American Wind Energy Association; Center for Energy Efficiency & Renewable Technologies; Citizens Utility Board of Wisconsin; Conservation Law Foundation; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; National Audubon Society; Natural Resources Defense Council; Northeast Energy Efficiency
<table>
<thead>
<tr>
<th>Organization</th>
<th>Full Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>Public Power Council</td>
<td>Public Power Council</td>
</tr>
<tr>
<td><strong>RRI Energy</strong></td>
<td>RRI Energy, Inc.</td>
</tr>
<tr>
<td><strong>Salt River Project</strong></td>
<td>Salt River Project Agricultural Improvement and Power District</td>
</tr>
<tr>
<td><strong>San Diego Gas &amp; Electric</strong></td>
<td>San Diego Gas &amp; Electric Company</td>
</tr>
<tr>
<td><strong>Solar Energy Industries</strong></td>
<td>Solar Energy Industries Association</td>
</tr>
<tr>
<td><strong>South Carolina Electric &amp; Gas</strong></td>
<td>South Carolina Electric &amp; Gas Company</td>
</tr>
<tr>
<td><strong>Southern California Edison</strong></td>
<td>Southern California Edison Company</td>
</tr>
<tr>
<td><strong>Southern Companies</strong></td>
<td>Southern Company Services, Inc.</td>
</tr>
<tr>
<td><strong>SPP</strong></td>
<td>Southwest Power Pool, Inc.</td>
</tr>
<tr>
<td><strong>Startrans</strong></td>
<td>Startrans IO, LLC</td>
</tr>
<tr>
<td><strong>Starwood</strong></td>
<td>Starwood Energy Group Global, LLC</td>
</tr>
<tr>
<td><strong>State Representative Sloan</strong></td>
<td>State Representative Tom Sloan</td>
</tr>
<tr>
<td><strong>Sunflower and Mid-Kansas</strong></td>
<td>Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC</td>
</tr>
<tr>
<td><strong>Trans-Elect</strong></td>
<td>Trans-Elect Development Company, LLC</td>
</tr>
<tr>
<td><strong>Transmission Access Policy Study Group</strong></td>
<td>Transmission Access Policy Study Group</td>
</tr>
<tr>
<td><strong>Transmission Agency of Northern California</strong></td>
<td>Transmission Agency of Northern California</td>
</tr>
<tr>
<td><strong>Upper Great Plains Transmission Coalition</strong></td>
<td>Upper Great Plains Transmission Coalition</td>
</tr>
<tr>
<td><strong>WECC</strong></td>
<td>Western Electricity Coordinating Council</td>
</tr>
<tr>
<td><strong>WIRES</strong></td>
<td>Working Group for Investment in Reliable and Economic Electric Systems</td>
</tr>
<tr>
<td><strong>Xcel</strong></td>
<td>Xcel Energy Services Inc.</td>
</tr>
</tbody>
</table>
Appendix B: *Pro Forma* Open Access Transmission Tariff

ATTACHMENT K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider’s coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider’s Tariff.

The Transmission Provider’s planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also include the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by state or federal laws or regulations consistent with the Final Rule in Docket No. RM10-23-000. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05-25-000.
The description of the Transmission Provider’s planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers and neighboring transmission providers;
(ii) The notice procedures and anticipated frequency of meetings;
(iii) The methodology, criteria, and processes used to develop a transmission plan;
(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;
(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;
(vi) The dispute resolution process;
(vii) The Transmission Provider’s study procedures for economic upgrades to address congestion or the integration of new resources;
(viii) The Transmission Provider’s procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by state or federal laws or regulations; and
(ix) The relevant cost allocation method or methods.

**Intraregional Transmission Planning**

The Transmission Provider shall participate in a regional transmission planning process
through which transmission facilities and non-transmission solutions may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must not be unduly discriminatory and must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable, as described in the Final Rule in Docket No. RM10-23-000. The regional transmission planning process shall be described in an attachment to the Transmission Provider’s Tariff.

The Transmission Provider’s regional transmission planning process shall satisfy the following seven principles, as set out and explained in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process shall also include the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by state or federal laws or regulations consistent with the Final Rule in Docket No. RM10-23-000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05-25-000.

Nothing in the regional transmission planning process shall include an unduly
discriminatory process for transmission project submission and selection. The regional transmission planning process shall provide on a not unduly discriminatory basis for the sponsor of a facility that is selected through the regional transmission planning process for inclusion in the regional transmission plan to have a right, consistent with state or local laws or regulations, to construct and own that facility and to recover the cost of that facility through the applicable regional cost allocation method.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;
(ii) The notice procedures and anticipated frequency of meetings;
(iii) The methodology, criteria, and processes used to develop a transmission plan;
(iv) The method of disclosure of criteria, assumptions and data underlying transmission plan;
(v) The obligations of and methods for transmission customers to submit data;
(vi) The dispute resolution process;
(vii) The study procedures for economic upgrades to address congestion or the integration of new resources;
(viii) The procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by state or federal laws or regulations; and
The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or methods that satisfy the six principles set forth in the final rule in Docket No. RM10-23-000.

**Interregional Transmission Planning**

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning issues related to interregional transmission facilities. This coordination between each pair of transmission planning regions must be reflected in an interregional transmission planning agreement filed with the Commission. The interregional transmission planning agreement must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently than separate intraregional transmission facilities.

The Transmission Provider must ensure that the following elements are included in any interregional transmission planning agreement in which it participates:
(1) A commitment to coordinate and share the results of each transmission planning region’s regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities;

(2) An agreement to exchange at least annually planning data and information;

(3) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions; and

(4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six principles set forth in the final rule in Docket No. RM10-23-000.
MOELLER, Commissioner, \textit{concurring}:

As I have repeatedly stressed in my years on this Commission, promoting investment in our nation’s transmission infrastructure has been my top policy priority.\(^1\) Robust electric transmission infrastructure is the ultimate “enabling” energy technology, as it can provide a more efficient electric system, enhanced reliability, increased access to less expensive and often cleaner resources, and the ability to harness location-constrained renewable resources. Conversely, the lack of adequate transmission investments often disproportionately raises consumer rates due to congestion, threatens the reliability of the nation’s bulk power system, and increases reliance on older and dirtier generating resources.

While I am not certain that every policy in this proposed rule will ultimately be adopted, I am certain that building needed transmission lines is often the lowest-cost way to improve the delivery of electricity service. Although the Commission could have addressed regional cost allocation several years ago when it first became apparent that the organized markets were not reaching consensus on the issue, that wait is over and the Commission is now considering specific proposals to resolve cost allocation.

\(^{1}\) NSTAR Elec. Co., 125 FERC ¶ 61,313 (2008) (Moeller, Comm’r, dissenting in part) (“… the Commission should do what it can to encourage capital investment in needed transmission infrastructure projects.”); Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana, 125 FERC ¶ 61,250 (2008) (Moeller, Comm’r, dissenting) (“… now is not the time for this Commission to discourage investment in needed transmission infrastructure.”); New York Indep. Sys. Operator, Inc., 129 FERC ¶ 61,045 (2009) (Moeller, Comm’r, dissenting) (“The main issue here is whether needed transmission is being built … I have encouraged investment in transmission infrastructure …”); Southern California Edison Co., 129 FERC ¶ 61,013 (2009) (Moeller, Comm’r, dissenting in part) (“The transmission that is needed in this nation will not be built unless the companies that build it can attract adequate investment dollars.”)
Given that the U.S. Congress is examining cost allocation at this time, our issuance of this proposed rule comes at a potentially sensitive time. While Congress is now considering several measures that deal directly with issues addressed in this proposed rule, I expect that this Commission will defer to the legislative branch as we move forward in our deliberations. This proposed rule, and the comments to follow, will provide the Congress with the framework of the issues that we consider relevant and the opportunity for Congress to provide further guidance to us. Thus, our action today is not intended to interfere with that process, but rather to add helpful information and evidence that will be useful in the formation of federal legislation.

Also controversial will be the question of whether incumbent utilities should retain rights of first refusal that were created under the Commission’s jurisdiction. Alas, the question of whether transmission developers can compete on par with an incumbent transmission-owning utility is no longer theoretical. In recent cases, the Commission has been confronted with particular situations where competitors could be discouraged (or altogether blocked) from building a transmission project if the incumbent utility retains the right of first refusal. While initial rulings have been rendered in these cases, the generic issue is ready for further discussion in this rulemaking.

Resolving controversial issues is rarely easy and I expect today’s proposed rule to be both lauded and criticized. The changes proposed here are significant, but the future success of the organized markets and the nation’s electric transmission system depend on resolving these long-debated and controversial issues.

Staff’s efforts here have resulted in a proposal that will lead to a much needed conversation on how to best encourage needed capital investment. This will not be an easy matter to address when it comes before the Commission for a vote on the final rule, and for that reason this Commission should carefully consider the comments that we will receive. I will do my part to ensure that this Commission does not lose sight of the ultimate goal: a final rule that results in needed capital investment.

_______________________
Philip D. Moeller
Commissioner

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation )
by Transmission Owning and ) Docket No. RM10-23-000
Operating Public Utilities )

COMMENTS OF THE
LARGE PUBLIC POWER COUNCIL

Jonathan D. Schneider
Jonathan P. Trotta

STINSON MORRISON HECKER LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036
JSchneider@stinson.com
JTrotta@stinson.com
(202)785-9100

Attorneys for the
Large Public Power Council

September 29, 2010
Washington, DC
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation )
by Transmission Owning and ) Docket No. RM10-23-000
Operating Public Utilities )

COMMENTS OF THE
LARGE PUBLIC POWER COUNCIL

TABLE OF CONTENTS
I. Introduction and Executive Summary .................................................................1
II. The Need for Reform (NOPR at PP 32 – 43) .................................................5
   A. LPPC Urges FERC to be More Rigorous in its Proposed
      Findings and Holdings. .................................................................5
III. Proposed Reforms – Transmission Planning (NOPR at PP 44 – 120) .............12
   A. Participation in Regional Planning Processes (NOPR at PP 45 – 54) .........12
      1. LPPC Members Have Committed to Regional and
         Interregional Planning Processes. .............................................12
      2. FERC Must Not Turn Regional Plans into
         Mandatory Templates. .........................................................16
   B. Public Policy Driven Projects (NOPR at PP 55 – 70) .........................19
      1. It is Unreasonable to Mandate that Public Policy be Taken
         into Account in Transmission Plans Other Than to the Extent it
         Translates into Actual or Anticipated Transmission Demand. .......19
      2. FERC Does Not Have Jurisdiction to Consider Broad Notions
         of Public Policy under the Federal Power Act. ..........................21
   C. Opportunities for Undue Discrimination against Non-incumbent
      Transmission Developers. (NOPR at PP 71 – 101) .......................22
      1. LPPC Does Not Generally Object to FERC's Proposed Tariff
         Revisions Specifying Terms under Which Non-Incumbent
         Transmission Developers Will Participate in the Planning Process. ....22
2. FERC Orders or Rules Compelling Utilities to Defer to Non-Incumbent Transmission Developers in the Construction of Facilities Needed to Serve Native Load Would be Beyond its Jurisdiction. .................................................................23

D. Interregional Coordination (NOPR at PP 102 – 120) ........................................29
   1. LPPC Members Will Participate in Consensus-Based Interregional Planning Processes. .................................................................29
   2. LPPC Members Cannot Commit to Entering FERC-Jurisdictional Agreements Containing Interregional Planning Protocols. ..........29

IV Proposed Reform - Cost Allocation (NOPR at PP 121 – 178) ..........................30
   A. Introduction ..............................................................................30
   B. The Commission Demonstrates No Basis for Generic Rate Reform and there is Substantial Evidence of Robust Transmission Development Without it. .................................................................33
   C. Cost Subsidization for Long-Line Transmission Development Tilts the Balance in Determining how to Meet Renewable and Carbon Control Goals, and will Engender Needless Controversy, Ultimately Impeding Project Development. .................................................................................40
   D. There is No Lawful Mechanism for Allocating Costs to Entities Without a Service Relationship and Contractual Privity Between the Transmission Provider and its Customers. .................................................................43
   E. Assuming, Arguendo, that Costs Can be Distributed Without Regard to a Service Relationship, an Allocation of Costs Based on "Benefits" Must Nonetheless be Consistent with FERC's Statutory Authority. .................................................................47
   F. Interregional Cost Allocation (NOPR at PP 170-178) ................................50

V. Compliance Filing Schedule (NOPR at 179 – 181) ........................................52

VI. The NOPR's Lack of Clarity in Several Key Areas Violates the Administrative Procedure Act. .................................................................53

VII. Municipal Participation in Transmission Planning and Cost Allocation ........54
   A. LPPC Members will Commit to Participate in Regional and Interregional Planning Processes, and in Regional and Interregional Cost Recovery Mechanisms where they Fairly Reflect Benefits Received. .................................................................54
B. Reciprocity Cannot be Expanded to Require Participation in Mandatory Region-Wide Cost Sharing, or to Require Municipalities to Alter Plans Deemed Necessary to Meet their Service Obligations. ........55

VIII. Conclusion ..........................................................................................................................57

Attachment – Planning Processes in the Eastern and Western Interconnections to Which LPPC Members are Parties.
I. Introduction and Executive Summary

These comments are submitted by the Large Public Power Council ("LPPC") in response to the Commission's Notice of Proposed Rulemaking ("NOPR"), issued in this docket on June 17, 2010, and the Notice Extending Comment Period, issued on August 10, 2010. LPPC is an association of 24 of the nation's largest municipal and state-owned utilities. It speaks for the larger, asset owning members of the public power community.¹

LPPC has long been a supporter of the Commission's open access framework under Order No. 888² and ensuing Order No. 890.³ Although LPPC members are exempt from

---

¹ Together, LPPC’s members own approximately 34,000 miles of transmission, representing nearly 90% of the transmission investment owned by non-Federal public power entities in the United States. LPPC’s members are Austin Energy, Chelan County Public Utility District No. 1, Clark Public Utilities, Colorado Springs Utilities, CPS Energy (San Antonio), ElectriCities of North Carolina, IID Energy (Imperial Irrigation District), JEA (Jacksonville, FL), Long Island Power Authority, Los Angeles Department of Water and Power, Lower Colorado River Authority, MEAG Power, Nebraska Public Power District, New York Power Authority, Omaha Public Power District, Orlando Utilities Commission, Plate River Power Authority, Puerto Rico Electric Power Authority, Sacramento Municipal Utility District, Salt River Project, Santee Cooper, Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Public Utilities.


Federal Energy Regulatory Commission ("FERC") jurisdiction for most purposes under section 201(f) of the Federal Power Act ("FPA"), 16 U.S.C. § 824(f), LPPC members providing significant transmission service themselves or through an RTO or ISO, and who own and/or operate transmission, committed nonetheless to offer open access service under publicly available Open Access Transmission Tariffs ("OATT"). Further, LPPC members have been voluntary participants in the regional planning processes set in motion under Order No. 890. In addition, and relevant to this docket, LPPC members have been leaders in the interconnection of renewable resources and have an avid interest in working to establish a framework that maximizes the reliable and economical integration of these resources into grid operations.

LPPC agrees with the Commission that further steps may be taken to advance regional planning and interregional coordination, but believes the Commission should be much encouraged by the additional work already underway through existing regional and interregional planning fora. It is not clear to LPPC that the Commission fully appreciates the extent to which this work is already being undertaken, as is discussed below. LPPC strongly supports FERC's inclination to encourage solutions that are developed by stakeholders within regions. Very substantial differences in electric systems across the nation require differing approaches to planning and cost allocation for new transmission facilities. The differences

---

4 See LPPC, Initial Comments of the in Response to Notice of Proposed Rulemaking, Docket Nos, RM05-25, et al., at p.15-17 (filed Aug. 8, 2006) ("LPPC Initial Comments"). This commitment was reflected in Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 418-602. LPPC members offering transmission service under such tariffs include: Austin Energy, Clark Public Utilities, Colorado Springs Utilities, CPS Energy (San Antonio), IID Energy (Imperial Irrigation District), JEA (Jacksonville, FL), Long Island Power Authority, Los Angeles Department of Water and Power, Lower Colorado River Authority, MEAG Power, Nebraska Public Power District, New York Power Authority, Omaha Public Power District, Orlando Utilities Commission, Platte River Power Authority, Puerto Rico Electric Power Authority, Sacramento Municipal Utility District, Salt River Project, Santee Cooper, Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Public Utilities

5 See LPPC Initial Comments at 26-27. For LPPC members within RTOs, planning is undertaken in conjunction with that RTO's activity. This is true of the Long Island Power Authority ("LIPA") and the New York Power Authority ("NYPAP"); both New York ISO ("NYISO") members, and Nebraska Public Power District ("NPPD"), a transmission-owning member of the Southwest Power Pool ("SPP").
relate to: (1) variances in RPS requirements across the states; (2) differences in the resource base and availability of renewable resources; (3) business models and market structure; and (4) the existing state of transmission infrastructure development. For these reasons, FERC is right to focus attention on regional developments, and not to impose a super-regional or interconnection-wide planning model on the nation.

LPPC urges the Commission to avoid imposing mandatory planning templates on regions. LPPC supports the Commission's determination not to "dictate which investments" should be undertaken by transmission providers. However, LPPC is concerned that the Commission's proposal to require public utilities to file criteria to evaluate proposed transmission lines, and the proposed directive to each region to develop a single transmission plan (as opposed to engaging in an open process), may amount to the same thing.

Transmission construction and siting are state-jurisdictional matters, and most transmission investment is undertaken by utilities in order to serve their native load. Outside RTO regions, that investment finds its way principally into rates for bundled sales regulated by state commissions or otherwise set at the local level. The fundamentally state-based nature of this investment is underscored by FPA section 217(b) ("Native Load"), which directs FERC to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load serving entities."

With respect to the role of non-incumbent transmission developers, LPPC embraces the proposal to include these entities in regional and interregional planning processes. However, as to the role that these developers may play in developing facilities employed by load-serving

6 NOPR at P 51, n.59.
entities to serve native load, LPPC asks the Commission to ensure that nothing in the NOPR would impede incumbent utilities in taking all steps necessary, including siting facilities, to meet their service obligations. LPPC disagrees strenuously with the Commission's premise that non-incumbent transmission developers are entitled to the FPA's protection against undue discrimination. The FPA protects customers from discrimination, not competitive transmission developers, as argued below. Furthermore, even if one assumed, for the sake of argument, that the protection against discrimination is applicable, the differences between transmission development needed by load-serving entities to meet their service obligations and for-profit transmission developers with a completely different set of obligations and goals amply justify differences in treatment. Nor does the Commission compile any significant record of discrimination.

As to cost allocation, LPPC believes the Commission has been wise to steer clear of calls for it to mandate interconnection-wide cost sharing. Further, the Commission is right to recognize that its precedent and governing legal authority require that it honor cost causation principles. As well, LPPC supports FERC's view that each region should approach cost allocation in a manner that suits its needs. LPPC members commit to participating actively in all regional and interregional discussions regarding cost allocation for new transmission facilities.

However, LPPC objects to the Commission's tentative determination not to accept regional cost recovery mechanisms that provide for funding of regional facilities exclusively though a "participant funding" mechanism, by which LPPC takes the Commission to mean a mechanism which assesses costs to those customers opting to use the facilities.7 LPPC does

7 Id. P. 168.
not agree that the Commission has the authority to establish a recovery mechanism for the cost of new transmission facilities across a region or between regions without respect to whether customers have a service relationship with the transmission developer. In the absence of an agreement by the customer to take transmission service from a service provider that has included the cost of such new facilities in its rates, LPPC sees no legal basis for cost recovery under the FPA. LPPC believes the Commission's proposal would be: (1) a mistake as a matter of policy; (2) inconsistent with governing rate setting precedent; and (3) outside the law, to the extent it purports to assess costs without a service relationship between transmission developers and a customer. LPPC further believes FERC's proposed approach would raise costs to consumers, unjustifiably subsidize selected (and not all) segments of the renewable supply industry, and mire the progress now being made in transmission development in needless controversy and litigation.

Complicating matters further, there is every reason to believe that with the potential for cost socialization, the planning process will become vastly more contentious, slowing down needed projects, as parties who do not see themselves benefitting from facilities, but nonetheless fear bearing the related costs, seek to thwart the projects, even as other entities seek to ensure that costs they might otherwise agree to incur themselves are offset by regional contributions.

II. The Need for Reform  (NOPR at PP 32 – 43)

A. LPPC Urges FERC to be More Rigorous in its Proposed Findings and Holdings.

Summarizing its tentative decision at the outset of the NOPR, the Commission comments that:

The proposed reforms are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better
support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. \(^8\)

These conclusions call for factual determinations that must be supported by substantial evidence. The Commission is not given a free pass with respect to the evidence necessary to support generic orders governing structural industry changes, and it has been reversed on several occasions for failing to marshal sufficient support. Most recently, in *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006) ("National Fuel"), the court found that FERC "provided no evidence of a real problem" to support changes in Order No. 2004 to rules governing standards of conduct, adding that the Commission instead relied on a "theoretical potential for abuse" by non-marketing affiliates. *Id.*, 468 F.3d at 841 (emphasis in original). According to the court, the information relied on by FERC included "mere restatements" of the alleged threat the Commission sought to remedy, and did "not constitute record evidence of abuse." The court went on to state that "[p]rofessing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making." \(^9\)

Similarly, in *Assoc. Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1985) ("AGD"), in reviewing FERC's rationale in Order No. 436 for industry-wide contract demand adjustment conditions, the court concluded that the Commission "failed to develop an adequate rationale in support of" its regulations. *Id.*, 824 F.2d at 1018. The court went on to state that FERC's justifications "seem peripheral to the problem the Commission set out to solve in [its] rulemaking." *Id.*, 824 F.2d at 1019. Further, the court held that the Commission's arguments

---

\(^8\) NOPR at P 1.

applied only "to a limited portion of the industry," and "hardly support[ed] the broad remedy adopted." *Id.* Based on the evidence presented in Order No. 436 and related precedent, the court concluded there was no support for "an industry-wide solution for a problem that exists only in isolated pockets." The court concluded that "the disproportion of [FERC's] remedy to ailment" rendered the order arbitrary and capricious. *Id.*

Here, as in *National Fuel* and *AGD*, the support FERC marshals for sweeping industry-wide change is quite thin, comprising just seven pages of conclusory material, at NOPR P 32-41. The entire substance of the Commission's ostensible evidence, and LPPC's response, is this:

- At NOPR P 33, FERC tentatively concludes that there are significant changes in the electric power industry since the planning processes under Order No. 890 took effect.

  The Commission's assertion that there have been significant changes since the effective date of Order No. 890 is wholly unsupported. At NOPR n.41, without any direct reference to the alleged changes, the Commission cites only a 2010 study prepared by Edison Electric Institute ("EEI") which actually documents a trend toward increased transmission investment in the past several years.\(^10\) The Commission makes no effort to review changes to the landscape of the industry since implementation of Order No. 890. In fact, it has been just two and one-half years since the effective date of Order No. 890's Attachment K,\(^11\) a period sufficiently short that it is only now possible to begin to assess the effect of these new programs.

- At NOPR P 34, the Commission concludes that "siting, permitting and cost allocation of transmission facilities face significant challenges." In support, FERC cites a single comment offered by PJM in a news release indicating that an


\(^{11}\) Preventing Undue Discrimination and Preference in Transmission Service; *Order Extending Compliance Action Date and Establishing Technical Conference*, 120 FERC ¶ 61,103 (2007) (Establishing December 7, 2007 as the effective date for Attachment K to the Open Access Transmission Tariffs).
additional line in the Eastern portion of its system would relieve congestion costs. On the strength of this observation, the Commission concludes at P 35 that "one deficiency that has arisen is the lack of a requirement for a regional plan, without which the construction of new facilities could be inhibited."

LPPC notes, at the outset, that a single anecdote regarding congestion costs on a portion of the PJM system is a terribly thin reed upon which to base a broad conclusion regarding the need to reform the planning process. It seems self-evident that the factors relevant to the completion of needed facilities within PJM are not related to other regions, particularly those that do not share planning processes remotely similar to PJM's. PJM's planning process is most unique. Of course, it already includes a regional transmission expansion plan ("RTEP"), which is the product of extensive regional-wide discussion and comment. What complexities beset the parties in that context, and why facilities the Commission believes should have been constructed were not undertaken, LPPC will not speculate upon. But it is worth emphasizing that the planning process in PJM has for some years been undertaken along with a program for broad cost socialization only recently upset by the Court in Illinois Commerce Commission v. FERC, 576 F.3d 470 (7th Cir. 2009) ("ICC v. FERC"). Quite possibly, parties opposed arguably needed facilities because they received little or no benefit from those facilities and therefore did not want to pay for them. Or, perhaps, as FERC points out, siting and permitting proved to be an obstacle. But if the latter was the case, there is nothing in the FPA or in the NOPR that would address those issues, since the Commission generally lacks siting authority.

At NOPR PP 36 – 37, FERC comments that "[a]nother deficiency that has arisen since the issuance of Order No. 890 involves transmission needs driven by public policy requirements established by state or federal laws or regulations," and adds that state RPS measures "accentuate the need for transmission. . ." The Commission concludes that "existing transmission planning processes were not designed to account for, and do not explicitly consider these types of public policy requirements established by state or federal laws or regulations." The Commission goes on to say that it "preliminarily finds that the failure to account explicitly for such public policy requirements in the transmission planning
process may result in undue discrimination and rates, terms and conditions of service that are not just and reasonable."

These concerns are baseless on a number of levels. First, it is worth observing that the state of play with respect to the number and ambition of state-based renewable energy portfolio requirements around the nation has not changed by orders of magnitude since the effective date of Order No. 890. Second, it is simply incorrect to assert that existing planning processes do not account for public policy requirements. As discussed at some length below, to the extent public policy requirements affect the demand for transmission service, there is absolutely no question that existing planning processes will take the policies into account. State-based Integrated Resource Planning ("IRP") protocols call for utilities to weigh a range of resource options and their public policy implications when considering how to meet demand. Further, pursuant to the Order No. 890-sanctioned study processes, the planning processes are required to study a certain number of hypothetical scenarios submitted by stakeholders that will, in all probability, reflect certain presumptions regarding policy requirements. Such studies will, as well, be undertaken on an interconnection-wide basis in the East through the Eastern Interconnection Planning Collaborative ("EIPC") and in the Western Interconnection through the Western Electricity Coordinating Council ("WECC").

12 In fact, since the effective date of Order No. 890, only four states (i.e., Kansas, Michigan, Missouri and Ohio) have enacted new RPS requirements, and a mere 4 additional states (Massachusetts, Maryland, Hawaii and Nevada) and the District of Columbia have increased their RPS targets. This is hardly representative of a need for widespread reform to promote transmission development. See State of the States: Update on RPS Policies and Progress Presentation, Lawrence Berkeley National Laboratory, at slides 6-8 (Nov. 2009), available at http://www.cleanenergystates.org/Meetings/RPS_Summit_09/WISER_RPS_Summit2009.pdf; see also Renewables Portfolio Standards in the United States: A Status Report with Data Through 2007, Lawrence Berkeley National Laboratory, at 3-4 (Apr. 2008), available at http://eetd.lbl.gov/ea/ems/reports/lbnl-154e.pdf.

Having said that, and as argued below, LPPC does not see the need for a broader requirement for system plans to reflect public policy in the abstract. As discussed below, LPPC is concerned that directing transmission planners to sift through arguably relevant laws and regulations, interpret those authorities, resolve conflicts and ascertain the impact these authorities will have on transmission demand will place unreasonable stress on the planning process, with inevitable conflict and delay as a consequence.

- At NOPR P 38, the Commission identifies as a "third deficiency...obstacles to non-incumbent transmission project developers' participation in regional transmission planning processes." Without recounting specific events, but citing certain parties' comments, the Commission concludes that the treatment of non-incumbent project developers in the transmission planning process constitutes undue discrimination.

LPPC welcomes the participation of non-incumbent transmission developers in regional and interregional planning processes. Indeed, these entities ought to (and generally do) participate in these processes. But LPPC disagrees strenuously with the Commission's view that non-incumbent transmission developers are within the class of entities to which the FPA protection against undue discrimination applies. The FPA protects customers from discrimination, not competitive transmission developers, as argued below. Furthermore, even if one assumed that the protection against discrimination is applicable, the differences between transmission development needed by load-serving entities to meet their service obligations and for-profit transmission developers amply justify differences in treatment, again as discussed below. Nor does the Commission compile any significant record of discrimination.

- At NOPR P 39, the Commission identifies as a fourth deficiency the lack of coordination between transmission planning regions. The Commission asserts that "...in the absence of such coordination between transmission planning regions, transmission providers may not identify more efficient and cost-effective solutions to the individual needs identified in their respective utility–level and regional planning processes, potentially including interregional transmission projects. The Commission concludes that "...the Order No. 890
transmission planning requirements may not be just and reasonable in that they may not be sufficient to address the need for greater coordination in interregional transmission planning."

Yet, the Commission's conclusions are bereft of any insight or analysis of the processes only recently undertaken pursuant to Order No. 890, and certainly the more ambitious study process now being undertaken through EIPC in the Eastern Interconnection and at WECC in the Western Interconnection. These processes are only now underway, and the Commission's tentative conclusion that they have not borne fruit is premature.

- At NOPR P 40, the Commission asserts that existing methods for allocating costs for new transmission "may not be just and reasonable because they inhibit the development of efficient, cost effective transmission facilities necessary to produce just and reasonable rates."\(^{14}\) Citing the need for new intra-regional and interregional facilities crossing transmission provider boundaries, the Commission says that there are few rate structures in place that provide for the allocation and recovery of costs for projects that are proposed to be located in more than one transmission planning region, which "creates a significant risk for transmission project developers that they will have no identified group of customers from which to recover the cost of their investment."\(^{15}\)

Rather than providing evidence, this passage simply assumes, without discussion, that there is something wrong with establishing a rate structure which reflects traditional cost causation theory, and the attendant incentives that project developers have to locate and size facilities in order to meet demonstrated market demand. In fact, many interregional lines have been built for decades by owners in different regions that recover their negotiated share of the project costs from their transmission customers by filing to include the new project costs in their respective transmission rate bases. LPPC believes this model is not broken and, as discussed further below, is convinced that heavily subsidizing transmission development by socializing its costs will not serve the public interest.

\(^{14}\) NOPR at P 39-41.

\(^{15}\) Id. P 41.
With this said, LPPC concludes there is effectively no evidentiary basis for the changes proposed in the NOPR. With no "evidence of a real problem" and little more than "theoretical potential for abuse," as was the case before the court in National Fuel, LPPC believes the Commission would be acting arbitrarily and capriciously to proceed on the scant evidentiary record compiled in the NOPR.

**III. Proposed Reforms – Transmission Planning** (NOPR at PP 44 – 120)

A. Participation in Regional Planning Processes (NOPR at PP 44 – 54)

1. LPPC Members Have Committed to Regional and Interregional Planning Processes.

The NOPR identifies alleged deficiencies in transmission planning and a perceived lack of coordination between regional transmission planning processes, adding that more efficient transmission solutions may be identified through regional planning than through independent evaluation by transmission providers.¹⁶ While LPPC agrees with the Commission that coordinated transmission study and development is important, the NOPR greatly underestimates the extent to which transmission projects are presently being studied and developed on a regional level throughout the nation.

In all regions of the nation in which LPPC members operate, processes are already in place or under development that address concerns highlighted in the NOPR and the Commission's interest in ensuring that needed regional and interregional transmission projects are studied and developed. To this end, LPPC members are committed to participating in regional and interregional planning processes, and are taking meaningful steps to improve interconnection-wide transmission planning in order to facilitate the development of

¹⁶ NOPR at P 39.
transmission facilities. Such coordinated efforts in each of the LPPC members' regions throughout the country are outlined herein, and discussed at length in the Attachment, below.\textsuperscript{17}

The southeast has adopted a bottom-up transmission planning process driven primarily by State-regulated resource planning processes that identify load growth and determine cost-effective, reliable solutions for meeting future demand. This process incorporates state and local "public policy" considerations, including the state-imposed "duty to serve" and results in a transmission plan that accounts for native load obligations and other firm transmission service commitments on a transmission system. Results from this process become inputs into utilities' Order No. 890 planning processes.

Regional transmission plans in the southeast are further reviewed by SERC Reliability Corporation ("SERC") and FRCC to facilitate simultaneous interregional feasibility and consistency in models and data and coordination occurs annually with other planning authorities in the Eastern Interconnection to produce interconnection-wide base cases that provide the foundation for transmission planning studies in the Eastern Interconnection.

Regional planning in the southeast is further integrated through the Southeast Inter-Regional Transmission Participation Process ("SIRPP"),\textsuperscript{18} which consolidates regional data and assumptions and develops planning models. SIRPP ensures consistency in data and facilities economic planning studies that involve impacts on multiple systems between regional planning processes. SIRPP also enables transmission owners to review regional data, assumptions and assessments being performed on an interregional basis.

\textsuperscript{17} This review focuses on non-RTO regions, and the accompanying coordinated interregional processes. Most LPPC members are located outside RTO and ISO boundaries. NYPA and LIPA are members of NYISO, while NPPD and Omaha Public Power District are members of SPP. Filings by those organizations will detail planning activities in those regions.

\textsuperscript{18} The SIRPP was established pursuant to a request from FERC Commission Staff during the initial Attachment K development process.
LPPC members of the Southwest Power Pool (“SPP”) Nebraska Public Power District (“NPPD”) and Omaha Public Power District (“OPPD”) are active participants in the planning process as described in Attachment O of SPP’s Tariff. A detailed description of SPP’s regional planning process is set forth in *Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010). NPPD, a member of the LPPC, recently joined SPP. *See Southwest Power Pool, Inc.*, 125 FERC ¶ 61,239 (2008).

Regional and interregional planning processes throughout the Eastern Interconnection are supplemented by the EIPC, which facilitates interconnection-wide planning and enables inputs from various stakeholders including state and federal policy makers and produces an interconnection-wide review of existing regional plans and transmission options associated with various policy options.

Transmission planning and expansion throughout the Western Interconnection is coordinated through the WECC and numerous regional and sub-regional planning groups ("SPGs"). LPPC members engage in joint regional transmission planning throughout the Western Interconnection through their participation in, among other regional and sub-regional planning groups, WestConnect and its Colorado Coordinated Planning Group ("CCPG"), ColumbiaGrid, the California Transmission Planning Group ("CTPG") and, ultimately, WECC.

The CCPG is a sub-regional process tasked with coordinating transmission planning information and sharing updated on active transmission projects. Transmission providers participating in CCPG submit their transmission plans for incorporation into CCPG transmission studies and plans, which are coordinated between neighboring sub-regional planning groups through the WestConnect transmission planning process. The WestConnect process enables coordination of study efforts between all SPGs within the WestConnect
planning area, and coordination with other Western Interconnection transmission providers and their SPGs through WECC's Transmission Expansion Policy Planning Committee ("TEPPC"), as discussed in the Attachment below.

LPPC members in the Pacific Northwest participate in ColumbiaGrid, which facilitates a "single-utility" approach to transmission planning. ColumbiaGrid coordinates with neighboring planning entities and SPGs through the WECC sub-regional and regional processes, and meets regularly with other SPGs to coordinate study activities, develop base case assumptions, and share planning information. LPPC members in California participate in the CTPG, which performs technical studies using California's Renewable Energy Transmission Initiative ("RETI") conceptual transmission plan to identify and coordinate transmission projects needed to meet state-wide renewable energy and RPS goals. The CTPG develops annually a California transmission plan that incorporates its participants' needs and identifies opportunities for joint transmission development.

WECC coordinates regional planning activities among SPGs, state and provincial agencies, balancing authorities and transmission providers in the Western Interconnection, and develops interconnection-wide databases for transmission planning analysis and reporting of all planned projects throughout the Western Interconnection.

WECC coordinates planned and proposed projects and identifies transmission needs and potential solutions through the TEPPC, which conducts Western Interconnection-wide economic studies in a transparent and open stakeholder process, and the Planning Coordination Committee's ("PCC") path rating process, which ensures that new projects will have no adverse impacts on existing facilities or approved projects. The TEPPC process is outlined in the Attachment, below. Importantly, TEPPC quantifies future transmission congestion and
examines the impact of transmission expansion scenarios, the results of which form inputs for regional and sub-regional processes. In this way, WECC supports a bottom-up/top-down approach to planning in the Western Interconnection that ensures that accurate, quality data and stakeholder-vetted assumptions and models are available for use in planning processes throughout the region.

WECC’s transmission expansion planning processes are undergoing changes to better evaluate the reliability implications of state renewable energy policies. In this manner, interregional transmission planning throughout the West already incorporates policy-based needs and requirements into expansion plans, consistent with FERC objectives.

Regional processes are, of course, also under way in RTOs and ISOs throughout the nation, including those in which LPPC members participate, though LPPC expects that the Commission may be relatively more familiar with those processes than those in the non-RTO regions.

Comprehensive regional, sub-regional and interregional/interconnection-wide processes, then, already exist and promote stakeholder involvement and coordination. The NOPR fails to provide substantial evidence supporting the conclusion that these existing processes are flawed or insufficient to meet the Commission's stated goals. Worse, LPPC is deeply concerned that adoption of the NOPR's proposals would complicate regional and sub-regional planning efforts that are otherwise effectively coordinating, studying and implementing needed transmission solutions, and may very well undermine the Commission's stated goals.

2. **FERC Must Not Turn Regional Plans into Mandatory Templates.**

LPPC cautions the Commission against turning the proposed requirement that regional planning processes produce a regional transmission plan into mandatory FERC-approved
templates for planning and construction of facilities. LPPC believes that such a requirement would substantially inhibit the open and transparent planning processes already under way, and that it would exceed the Commission's jurisdiction.

LPPC notes, preliminarily, that the Commission's intention in this area is not altogether clear. At NOPR P 50, n.59, the Commission states that it does not propose "to dictate which investments identified in a transmission plan should be undertaken by transmission providers," as the Commission notes would be consistent with Order No. 890. Then again, while the NOPR does not say that the regional transmission plans it would direct must be filed with FERC, it does contemplate that the Commission will exercise oversight of the criteria pursuant to which facilities are included in regional plans, and that "each public utility transmission provider must revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a project in a regional transmission planning process." Such criteria "must not be unduly discriminatory or preferential." When these provisions are taken together, it is difficult to know whether the Commission is contemplating a process pursuant to which it would direct transmission construction pursuant to FERC-approved transmission plans, perhaps upon complaint. If that is indeed the case, LPPC cautions the Commission that it would act on questionable jurisdictional grounds. LPPC notes, first, that transmission siting and construction are predominately state-based matters. Most transmission construction is undertaken for load-serving entities for the purpose of serving their native load. With the limited exception of those facilities designated in

19 See NOPR at P 50.
20 Id. P 70.
21 Id. P 90.
connection with congestion corridors under FPA section 216, 16 U.S.C. § 824(P), siting authority and construction oversight are exclusively state-based functions. *See Piedmont Environmental Council v. FERC*, 558 F. 3d 304 (4th Cir. 2009). Moreover, the overwhelming bulk of the nation's transmission investment outside of RTO regions is dedicated to bundled sales service, and the transmission revenue requirement for this investment is established in state-jurisdictional rates.

Transmission investment and planning is, accordingly, an area suffused with state-based concerns. FPA section 217 ("Native Load Service Obligation") reinforces this conclusion in two important respects. FPA section 217(e), 16 U.S.C. § 824q(e) ("Obligation to Build"), specifies:

Nothing in this chapter relieves a load-serving entity from any obligation under State or local law to build transmission or distribution facilities adequate to meet the service obligations of the load-serving entity.

Further, FPA section 217(b)(4), 16 U.S.C. § 824q((b)(4), specifies:

The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities…

In addition, it bears pointing out that FPA section 202(a), 16 U.S.C. § 824a(a), stipulates that "…the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission and sale of electric energy…”

Together, these provisions make it clear that FERC has no authority to direct utilities to carry out specific transmission plans, to undertake construction according to those plans, or to

\[\text{\textsuperscript{22}}\]

16 U.S.C. § 824a(a) (emphasis added).
transfer responsibility for projects in their construction plans to non-incumbent transmission developers, as may be contemplated in the proposed rule. Instead, the FPA plainly contemplates that such plans are largely a state concern, and that such coordination as FERC may engender will be accomplished on a voluntary basis, and in a manner that facilitates the ability of load-serving entities to meet their service obligations. Again, LPPC emphasizes that its members are committed to the open and transparent regional planning protocols promulgated under Order No. 890. Further, LPPC members are participating in interregional planning processes, and commit to enhancing and building on those programs, as discussed below. But having said that, LPPC does not think the Commission can or should take the further step of assuming it has the authority to direct utilities to undertake specific siting and construction programs.

B. Public Policy Driven Projects (NOPR at PP 55 – 70)

1. It is Unreasonable to Mandate that Public Policy be Taken into Account in Transmission Plans Other Than to the Extent it Translates into Actual or Anticipated Transmission Demand.

FERC proposes to require public utility transmission providers to amend their OATTs in order to provide that local and regional transmission planning processes will consider public policy requirements established by state or federal laws or regulations that may drive transmission needs. Rather than specifying the public policy requirements established by relevant state and federal laws or regulations, the Commission proposes to require each public utility transmission provider to coordinate with customers and stakeholders in order to identify relevant state and federal laws and regulations.

23 NOPR at P 64.
24 Id. P 65.
The proposed requirement would be unnecessary, potentially confusing and ultimately counterproductive. There is no doubt that state and federal law and regulations may very well have an ultimate impact on system planning. But, LPPC notes, first, that there are a wealth of federal and state laws and regulations bearing on system planning. By leaving open for further discussion how system planners and interested parties will sift through these requirements in developing priorities and ensuing planning decisions, LPPC is most concerned that the proposed directive would engender nearly endless debate and controversy.

Even among those state laws that will have an obvious effect on demand, such as state-based RPS requirements, actual impacts will call for the exercise of subjective judgments. There are many ways to respond to an RPS, and responses will vary by utility and by state. The options include reliance on local renewable resources, recourse to demand response and efficiency initiatives (reducing demand for transmission), and the use of remote renewable generation (increasing demand for transmission). Customarily, all such options are identified and evaluated by resource planners, following which the load-serving entity selects "winners." Those decisions then dictate site-specific points of injection and withdrawal on the grid, enabling transmission planners to draw appropriate conclusions regarding the need for transmission upgrades.\(^{25}\)

The bottom line is that it would not be cost effective, nor would it further environmental goals, for the Commission to direct transmission planners to select multi-billion dollar interregional transmission projects before load-serving entities make their determinations regarding needed resources. Ultimately, all that matters in connection with the formulation of a

\(^{25}\) This statement is not intended to imply that transmission upgrade costs are disregarded by resource planners. Resource planners normally include an estimate of the transmission costs associated with each option they evaluate.
transmission plan is the projected demand for transmission service. Asking transmission planners to divine when and where their customers will need transmission upgrades based on their analysis of public policy is a prescription for confusion, potential stranded costs, and litigation that may set back existing planning processes for years.

2. **FERC Does Not Have Jurisdiction to Consider Broad Notions of Public Policy under the Federal Power Act.**

LPPC cautions the Commission that outside ascertaining the impact that public policy may have on transmission demand, an effort directly to advance such policies is beyond the Commission's jurisdiction. It is well settled that FERC's statutory mission under the FPA is to ensure reliable service at just and reasonable rates. *See National Assoc. for the Advancement of Colored People, et al. v. FPC, 425 U.S. 662, 669-70 (1976) ("NAACP") ("the principle purpose of [the FPA] was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices.").* As the Supreme Court concluded in *NAACP, Congress' direction to the Commission to act in furtherance of the "public interest" under the FPA "is not a broad license to promote the general public welfare." Id., 425 U.S. at 669-70. Accordingly, it is clear that FERC lacks the authority to advance "public policy," broadly construed. Rather, the Commission's mission under the FPA is confined to ensuring that reliable electric service is provided at just and reasonable rates.\(^{26}\)

It is also worth pointing out that the Commission has on several occasions itself recognized this limitation in connection with its authority to consider environmental policy objectives under National Environmental Policy Act ("NEPA"). *See Monongahela Power, 39 FERC at 62,097.* While FERC's NEPA-related responsibilities extend to oversight of

\(^{26}\) *See Monongahela Power Co., 39 FERC ¶ 61,350, at 62,097, reh'g denied, 40 FERC ¶ 61,256 (1987) ("Monongahela Power").*
hydroelectric projects and natural gas pipeline facilities, they "do not extend to electric rate filings pursuant to [FPA] section 205." In fact, the Commission's regulations implementing NEPA provide, in relevant part, that "neither an environmental assessment nor an environmental impact statement will be prepared for [projects or actions including] [e]lectric rate filings submitted by public utilities under [FPA] sections 205 and 206 [and] the establishment of just and reasonable rates."  

LPPC also sees the potential for considerable mischief in asking transmission planners to seek their own counsel in ascertaining the public policies to which they must respond. In fact, the discretion that this approach would interject into the planning process would seem to be an open door to potential discrimination, and a nightmare to enforce, as parties debate whether planning adequately responds to a variety of potentially competing policies.

C. Opportunities for Undue Discrimination against Non-Incumbent Transmission Developers. (NOPR at PP 71 – 101)


LPPC does not generally object to FERC's proposed tariff revisions specifying the terms under which non-incumbent transmission developers will participate in the planning process. The effort to specify procedures for ensuring that non-incumbent transmission developer

---

27 Id. (noting that to implement NEPA, the FPC, FERC's predecessor agency, issued policy statements requiring the preparation of environmental impact statements in connection with the construction of facilities subject to its licensing jurisdiction). The Commission has on several occasions recognized that its review of electric rate filings is not subject to NEPA and, therefore, did not order environmental impact statements to be prepared. See Southern Co. Services, Inc., 22 FERC ¶ 61,047 (1983); Southern Co. Services, Inc., 12 FERC ¶ 61,081 (1980); In the Matter of NEPOOL Power Pool Agreement, 48 FPC 1477 (1972).


29 NOPR at PP 90-96.
proposals may be evaluated, and the developers' fitness to complete projects determined, is generally sensible.

LPPC does object to the Commission's tentative determination\(^{30}\) not to require a transmission developer to participate in the regional transmission planning process if it does not seek to use the regional cost allocation process. The Commission reasons that in such cases, the fact that beneficiaries need not be identified for cost allocation purposes appropriately relieves the project developer of an obligation to participate in regional planning.\(^{31}\) This reasoning is unsound. The presence of substantial new facilities interconnected with the electrical grid must be taken into account and studied in regional and interregional processes. Regardless of the provisions governing cost recovery for such facilities, they will have impact on grid capabilities and operations that cannot be ignored. There is no basis for permitting the developers of such projects to exempt themselves from regional fora.

2. **FERC Orders or Rules Compelling Utilities to Defer to Non-Incumbent Transmission Developers in the Construction of Facilities Needed to Serve Native Load Would be Beyond its Jurisdiction.**

Where utilities identify facilities that are needed to serve their native load, they must be permitted to undertake construction in order to meet their service obligation. Although LPPC is not certain of FERC's intention in this area outside the RTO/ISO setting, LPPC emphasizes that a utility's ability to construct facilities it needs to meet its service obligation cannot be impeded.

Outside the RTO/ISO setting (where FERC clearly has proposed to eliminate any rights of first refusal to construct transmission facilities that may be granted to incumbent utilities), FERC's intention with respect to incumbent utility rights is unclear. At NOPR P 87, the

---

\(^{30}\) *Id.* P 99.

\(^{31}\) *Id.*
Commission tentatively concludes that "there appear to be opportunities for undue discrimination and preferential treatment against non-incumbent transmission developers with existing regional transmission planning processes." The Commission goes on to assert that "…it may be unduly discriminatory or preferential to deny a non-incumbent transmission developer that sponsors a project as part of a regional transmission plan the rights of an incumbent transmission provider."  

At NOPR P 97, the Commission states:

We emphasize that these proposed reforms would apply only to facilities that are evaluated in a regional transmission planning process and selected for inclusion in a regional transmission plan. We do not propose to modify any existing obligation for an incumbent transmission provider to build unsponsored projects that are identified as necessary in the regional transmission plan… (emphasis added)

Read in isolation, that passage suggests that where non-incumbent transmission developers sponsor new projects (even if they are identified by an incumbent utility as essential in performing their service obligation), they may be given a federal priority to build facilities. Conceivably, the Commission intends these priorities to be enforceable to the extent commitments are made pursuant to the interregional planning agreements that the Commission proposes must be filed with the Commission and subject to protocols for evaluating sponsored projects. Nonetheless, FERC goes on to state:

We also emphasize that these proposed reforms would only affect a right of first refusal established in a transmission provider's OATT or agreements subject to the Commission's jurisdiction. This Proposed Rule does not address, propose to change, or seek to preempt any state laws or regulations.

Accordingly, LPPC is genuinely uncertain whether it is FERC's intention to leave unaffected the construction plans a utility may have to meet its native load service obligation, or if FERC

______________________________

32 Id. P 87.
33 See id. P 118.
34 Id. P 98.
intends that non-incumbent transmission developers be given the opportunity to compete to construct such facilities, perhaps on the ground that their facilities serve markets more efficiently.

LPPC would very much like to think that the Commission's intention is to leave intact incumbent utilities' authority to do what they must to carry out their obligation to serve native load, by their own lights and subject to state regulatory oversight. And it certainly seems possible that the role for non-incumbent transmission developers that the Commission envisions involves projects that are either unrelated to LSE service obligations, or in which traditional utilities choose to work with non-incumbent developers. But, if the Commission's aim is otherwise, LPPC objects on the ground that the Commission lacks statutory authority to act in this manner.35

FERC's reliance on the FPA's prohibition of undue discrimination to promote the rights of non-incumbent transmission developers lacks any statutory basis. FPA section 205(b) proscribes both "any unreasonable differences in rates" and any "undue preference or advantage."36 Yet, it is well settled that "[t]he purpose behind [FPA] section 205(b) is the protection of the consumer's interest" (emphasis added).37 Contrary to the NOPR's apparent assumption, the intent of the statute's undue discrimination protections "is to protect consumers [ ] from being placed at a competitive disadvantage with other [similar customers]."38 There are

35 LPPC does not object to the location of non-incumbent facilities within the footprint of existing utility systems, nor does it think that a right of first refusal must be maintained by incumbent utilities for all such facilities. LPPC's concern is rather to ensure that utilities have the unfettered right to build facilities that are needed in order to serve their load.

36 16 U.S.C. 824d(b); see also Alabama Elec. Co-op., Inc. v. FERC, 684 F.2d 20, 28 (D.C. Cir 1982).

37 Pub. Service Co. of Ind., Inc. v. FERC, 575 F.2d 1204, 1213 (7th Cir. 1978) ("Indiana"); see St. Michaels Util. Comm'n v. FPC, 377 F.2d 912, 915 (4th Cir. 1967) ("St. Michaels").

38 Indiana, 575 F.2d at 1212 (emphasis added); see City of Frankfort, Ind. v. FERC, 678 F.2d 699, 707 (7th Cir. 1982).
essentially two (and only two) types of undue discrimination: treating similar customers differently or according similar treatment to dissimilar customers. *Alabama Electric Cooperative v. FERC*, 684 F.2d 20, 27-28 (D. C. Cir. 1984). But in each case the discrimination is between a public utility’s customers or classes of customers (including the public utility’s treatment of itself as a customer). Thus, while section 205(b) plainly protects competitors of jurisdictional service providers in their capacity as customers (including protection against anticompetitive discriminatory conduct), the FPA’s undue discrimination protections simply do not extend to non-incumbent transmission providers as competitors.

To the same effect, in *City of Frankfort*, addressing a municipal customer's undue discrimination claim against a public utility, the court noted that FPA section 205 provisions "regarding unlawful preference or advantage in setting of public utility rates requires that utility customers be treated fairly (emphasis added)." *City of Frankfort*, 678 F.2d at 704. Similarly, the court in *Indiana* stated that "the anti-discrimination policy in [FPA] section 205(b) is violated [ ] where one consumer has its rates raised significantly above what other similarly-situated consumers are paying." The *Indiana* court went on to note that, "[i]n such a case, the lone customer" has recourse to the Commission under FPA section 205(b) when it is put in "an unjustifiably non-competitive position." *Indiana*, 575 F.2d at 1213. According to the *Indiana* court, the Commission, in evaluating utility requests to increase rates to customers, "should not ignore its responsibility to the consumer under [FPA section] 205(b)." *Id.* The rights of

---

competitors, then, are neither protected nor contemplated in FERC's FPA section 205(b) proscription against undue discrimination.39

Underscoring the illogic of the proposed expansion of the anti-discriminatory provision in the FPA to transmission developers in their role as competitors of existing transmission providers is the fact that the Commission plainly lacks general jurisdiction over the siting, construction or ownership of transmission facilities, matters that Congress intentionally left to the states, as demonstrated by a comparison between the FPA and the Natural Gas Act ("NGA"). FPA section 201(a), 16 U.S.C. § 824(a), provides for FERC jurisdiction over "the business of transmitting and selling electric energy" at wholesale with "such Federal regulation [] to extend only to those matters which are not subject to regulation by the States." In contrast, NGA section 7, 15 U.S.C. § 717f, expressly grants to FERC siting and construction authority over natural gas pipelines.

Even assuming, arguendo, that non-incumbent transmission providers – in their role as transmission providers rather than customers – fall under the ambit of the FPA's undue discrimination protections, these transmission providers are not similarly situated to incumbent utilities. FERC's authority under the FPA to remedy unlawful preference or advantage in public utility rates is grounded in protecting consumers from being placed at a competitive disadvantage with respect to other similar customers. See City of Frankfort, 678 F.2d 699. Indeed, the FPA does not prohibit all discrimination, only undue discrimination, and FERC has

39 The Commission has itself commented that its job is to protect competition, not competitors. See Entergy Services Inc., 64 FERC 61,001 at 61,013, n.66 (1993) (citing Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc., 429 U.S. 477, 487-89 (1977); Cargill, Inc. v. Montfort of Colorado, Inc., 479 US 104, 115-17 (1976)). To the extent the Commission has conceptualized its open access policy to be in furtherance of antitrust principles, it is further worth noting that the Supreme Court has made clear that the antitrust laws "were enacted for the protection of competition, not competitors." Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc., 429 U.S. 477, 487-89 (1977) (quoting Brown Shoe Co. v. US, 370 U.S. 294, 320 (1962)).
generally found that discrimination is "undue" when there is a difference in rates, terms or conditions among similarly situated customers. There is nothing unduly discriminatory about treating differently situated entities differently. Unlike non-incumbent transmission developers, by virtue of their state-based franchises, incumbent utilities are legally bound by a "duty to serve," an obligation that carries with it a commitment to construct and maintain facilities necessary to render reliable, cost-effective service to customers in their service territories. Non-incumbent transmission providers are self-evidently not bound by a similar obligation.

FPA Section 217(e), 16 U.S.C. § 824q(e), expressly recognizes the primacy of a franchised utility's obligation to do what is needed in order to fulfill its obligation to serve, specifying that "[n]othing in this chapter relieves a load-serving entity from any obligation under State or local law to build transmission or distribution facilities adequate to meet the service obligations of the load-serving entity." The flip side of that coin is the plain implication that the Commission must do nothing to impede load-serving entities' ability to meet their service obligations, and to take primary responsibility for the construction of the facilities necessary to do so.

LPPC adds that if, indeed, it is the Commission's intention to require utilities to defer to non-incumbent utilities in connection the construction of facilities that are required, even in part, for reliability purposes, meaningfully more thought must be given to the practical issues


41 See, e.g., Sebring Utils. Comm'n v. FERC, 591 F.2d 1003, 1009 n.24 (5th Cir. 1979) (the "essence of the principle" of the prohibition against undue discrimination "is that those who are similarly entitled must be treated equally"); Transwestern Pipeline Co., 38 FERC ¶ 61,175, at 61,433 (1986) ("Undue discrimination is in essence an unjustified difference in treatment of similarly situated customers.").
presented by that approach. It is not clear to LPPC, among other things, whether utilities' service obligations that depend on the completion of non-incumbent facilities may be mitigated if the facilities are unavailable.

D. Interregional Coordination (NOPR at PP 102 – 120)

1. LPPC Members Will Participate in Consensus-Based Interregional Planning Processes.

LPPC members stand ready to participate in interregional planning processes reflecting the basic precepts articulated by the Commission in the NOPR at P 117-118, viz.,

- Coordination and sharing results of respective regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities;
- the exchange at least annually of planning data and information;
- a process for identifying and jointly evaluating transmission facilities that are proposed to be located in both regions; and
- a commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process

As described in the Attachment, LPPC members are already actively engaged in regional and interregional planning.

2. LPPC Members Cannot Commit to Entering FERC-Jurisdictional Agreements Containing Interregional Planning Protocols.

While LPPC members will commit to participate in interregional processes consistent with Commission's articulated principles, they cannot commit to enter into the interregional planning agreements that the Commission contemplates will be filed with it. For one thing, apart from the general topics the Commission has listed for consideration in these agreements, it is not possible at this time for LPPC members to ascertain what commitments may be called for in such agreements. Among the many matters that remain undetermined are whether these
agreements: (1) will carry with them specified or open-ended liability; (2) may include an obligation to defer to regional or interregional transmission plans that would, in the members' judgment, interfere with what must be done to honor an obligation to serve; (3) may impose construction obligations or other unanticipated costs on the members; and (4) will be subject to FERC modification in ways that will affect members' responsibilities and liabilities.

The authority pursuant to which LPPC members enter into binding contractual commitments is quite varied. Because LPPC members are creatures of state and municipal governments, and are created by statute or municipal ordinance, their authority to enter into binding arrangements is in all cases tightly circumscribed in a manner that is consistent with their fiduciary responsibilities and will protect state and municipal sovereignty. Members are also restricted in their contracting practices by covenants in their financing arrangements, and cannot volunteer to enter into agreements that would, among other things, violate or jeopardize a private activity bond rule for purposes of section 141 of the Internal Revenue Code of 1986, 26 U.S.C. § 141, or any successor statute or regulation. With all of this in mind, LPPC members cannot commit to enter agreements at this time, and cannot do so until substantial additional definition and assurance is provided.

IV. Proposed Reform - Cost Allocation (NOPR at PP 121 – 178)

A. Introduction

At NOPR P 156, the Commission indicates that it proposes "to more closely align transmission planning and cost allocation processes." LPPC can support this approach, to the extent that what is contemplated is the creation of a regional forum enabling parties to consider mechanisms for recovering the costs of planned new transmission facilities in a regional setting.

In addition, LPPC supports certain of the guideposts established by the Commission for these discussions. LPPC agrees with the Commission that the approach to cost recovery must
reflect regional characteristics, and that a national template is not advisable. Some of the fundamental differences between regions bearing on transmission plans and cost recovery include dramatically different generation resource bases, the state of existing infrastructure development and different market structures. Accordingly, LPPC supports the Commission's decision\textsuperscript{42} not to proceed with a uniform template for the treatment of cost across regions.

As well, LPPC agrees with the Commission that "those that receive no benefit from transmission facilities, either at present or in any likely future scenario, must not be involuntarily allocated the costs of those facilities."\textsuperscript{43} While that proposition might seem self-supporting, LPPC understands that there are those who would encourage the Commission to mandate socialization of cost on a regional or even interconnection-wide basis. FERC's decision to step back from the brink on that issue is sensible. On a related note, LPPC supports the Commission's tentative conclusion\textsuperscript{44} that costs for intraregional facilities should not be allocated to entities outside the region absent voluntary agreement.

LPPC cannot agree, however, with the Commission's tentative conclusion that a regional plan which relies exclusively on a “requestor pays” approach will in all cases be unacceptable.\textsuperscript{45} The Commission itself notes that it only recently accepted quite a number of Order No. 890 compliance filings from utilities outside RTO and ISO footprints in response to Order No. 890

\textsuperscript{42} NOPR at P 165.

\textsuperscript{43} \textit{Id.} P 164, item 2.

\textsuperscript{44} \textit{Id.}, item 4.

\textsuperscript{45} \textit{Id.} P 168. The NOPR refers to this approach as “participant funding,” although that terminology is drawn from cases in which the costs at issue were incurred by transmission providers providing service to their customers on a single system. As used in the NOPR, the term refers to the recovery of costs by entities spanning two or more transmission provider systems from entities requesting service on the new facilities. Since the term “participant funding” is used by the NOPR out of context, LPPC instead refers to an approach for recovery from customers taking service over a transmission developer’s lines spanning two or more transmission provider systems as a “requestor pays” approach.
that rely exclusively the allocation of transmission costs to entities which agree to pay them. A Commission order directing that this approach be changed can only follow lawfully from a finding that rates in regions which employ a participant funding approach are unjust and unreasonable, or that they are unduly discriminatory. Yet, as discussed below, the Commission fails to establish a record demonstrating the need for generic rate reform, and there is substantial evidence of robust transmission development without it.

From a policy standpoint, LPPC sees in proposals for broad cost socialization of regional and interregional transmission projects the perversion of cost signals that are essential in ensuring that resources are appropriately used and conserved, and that cost to consumers are minimized. Moreover, by marrying transmission planning to cost socialization, LPPC envisions endless controversy, as facilities that may otherwise have been supported by voluntary agreement are endlessly debated and litigated by parties hoping to shift costs to others.

As a matter of law, LPPC sees no basis for the Commission to permit transmission developers to assess costs to entities other than their customers. The FPA grounds the Commission’s authority on a service relationship between a utility and its customers. Absent the provision of service to a customer under a tariff or contract, there is no authority to assess costs.

Further, LPPC is concerned that in evaluating the quantum of proof needed to impose costs on entities based on an assessment of ostensible "benefits," the Commission is prepared to act on the strength of less-than-rigorous evidence. Judicial precedent and the Commission's own ratemaking tradition call for the Commission to honor "cost causation" as the fundamental

46 As discussed above, the Commission lacks a statutory basis for protecting non-incumbent transmission developers from discrimination, leaving its authority to ensure that rates are not unjust and unreasonable as the remaining basis for action in this area.
touchstone for rational cost allocation. Yet, LPPC is concerned that the Commission may be giving no more than perfunctory consideration to this concept.

B. The Commission Demonstrates No Basis for Generic Rate Reform and there is Substantial Evidence of Robust Transmission Development Without it.

The Commission has the authority to change rates under the FPA only upon a finding that existing rates are unjust and unreasonable. Yet, the ostensible findings the Commission makes in support of generic rate reform – and its view that participant funding for region-wide transmission projects is impermissible – are thin, and certainly not applicable nation-wide. The Commission makes only two assertions of fact in articulating "The Need For Reform" at NOPR PP 148 – 154. These are that:

- "...further expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions." and

- "...the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of location-constrained renewable energy resources that are frequently remote from load centers, as well as a growing need for new transmission facilities across several utility and/or RTO or ISO regions."

Apart from these conclusory statements, the NOPR is bereft of any record evidence demonstrating unfulfilled transmission needs that can only be addressed through the rate reforms the Commission suggests. Perhaps regional power markets have experienced some expansion in recent years, and perhaps this has created some incremental demand for cross-regional wholesale transmission service. But the Commission offers no evidence of these

47 See Atlantic City Elec. Co. v. FERC, 295 F.3d 1 at 10 (D.C. Cir. 2002) ("The courts have repeatedly held that FERC has no power to force public utilities to file particular rates unless it first finds that existing filed rates unlawful.")

48 NOPR at P 150.

49 Id. P 151.
phenomena, and LPPC members are unaware of any groundswell of complaints in the regions in which they serve from load serving entities or state officials claiming that the transmission system is inadequate to reliably serve native load. Equally important, the Commission offers no evidence that reforms of the type it entertains in the NOPR, including the elimination of participant funding for cross-regional facilities, are a necessary or satisfactory solution to the perceived problem. As the court reminded the Commission in National Fuel, "]p]rofessing that an order ameliorates a real industry problem, but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making."^50

As to the Commission's assertion that the increasing adoption of resource policies and RPS requirements is driving increasing interest in location constrained renewable resources, it is worth observing, first, that state-based RPS requirements are not ubiquitous. In the Southeast, e.g., only North Carolina has an RPS requirement (i.e., 12.5% by 2021), ^52 and there is no suggestion in any quarter that a regional mechanism for funding transmission is needed in order to satisfy that requirement. Moreover, nation-wide, there is no indication that RPS requirements have increased meaningfully in the period since the issuance of Order No. 890.^53

Turning to what we do know, there is very good reason to conclude that transmission investment has increased substantially in recent years, while the anticipated trend continues to be upward. Moreover, regional and interregional transmission project development continues


^52 Id.

^53 See supra, p. 8-9, n.11.
for projects that enjoy market support without the inefficiencies that come with cost socialization. Estimated future transmission expenditures illustrate that this is a lasting trend.

In its recent report on nation-wide transmission infrastructure investment, EEI indicates that "[d]espite the economic downturn, the investment being made by EEI member companies is significant and growing, and reflects preparation for future customer needs." According to EEI, from 2001 to 2008 its members, who represent approximately 70 percent of the electric power industry in the country, invested nearly $57.5 billion in transmission infrastructure improvements. EEI adds that while its Report is not a comprehensive compilation of all projects being pursued by its membership, the representative projects in the Report total nearly $56 billion (nominal dollars) in expected future transmission system investments from 2009 through 2020 (see Figure 1). According to EEI, this is only a portion of the total transmission investment anticipated through 2020 by EEI member companies. EEI's members invested $9.1 billion in 2008, with planned additional investments of $33.9 billion in the transmission system between 2009 and 2011.

54 See EEI Report at iii. EEI's Report focuses on projects that were completed in 2009 or are expected to be completed by 2020, representing a one year back looking and 10 year forward looking window. Id., vii. EEI's members represent approximately 70 percent of the electric power industry in the U.S. Id.

55 Id. The $57.5 billion figure is in 2008 dollars.

56 Id.

57 Id., vii.
Further, of particular significance in this docket, the vast majority (i.e., 70 percent) of transmission investment and development is interstate (see Figure 2). According to EEI, the large interstate projects included in its Report span multiple states and account for approximately 10,000 circuit miles of transmission representing $39 billion (nominal dollars) of investment.\textsuperscript{59}

\textbf{Figure 1: Transmission Investment – 2001-2020}\textsuperscript{58}

\textsuperscript{58} Id.
\textsuperscript{59} Id., viii.
Similarly, most (i.e., 66 percent) of the representative projects in EEI's Report are or have been developed to facilitate the integration of renewable resources, with an accompanying transmission investment cost of approximately $37 billion (nominal dollars). EEI references several specific projects falling into this category of transmission development, including the Northeast Energy Link ("NEL"), Green Power Express, and the Canada-Pacific Northwest-California Transmission Project ("CNC Project"), all of which are regional or interregional in nature. The NEL is a proposed 240-mile, 1,100-MW high-voltage DC transmission line stretching from Northern Maine to Northeast Massachusetts, and will deliver cost effective renewable and low-carbon resources located in northern New England and the Canadian Maritimes into the Northeast Massachusetts load zone. Green Power Express is a vast 765-kV transmission overlay project spanning numerous states and several regions from the Midwest through the Great Plains. With an estimated cost of between $10-12 billion, Green Power Express...
Express consists of nearly 3,000 miles of transmission line to transport primarily wind resources to Midwest load centers and further east.\textsuperscript{63} The CNC Project will transport up to 3,000 MW of power from renewable resources in British Columbia, Canada to the Pacific Northwest and northern California, over a 1,000 miles long transmission line. As EEI indicates, the CNC Project "will enable and advance inter-regional and international development and integration of renewable energy resources, as well as provide a platform for integration and coordination of a number of regional transmission projects now being considered in the Pacific Northwest."\textsuperscript{64}

In addition to the projects recognized in the EEI Report, other regional and interregional merchant transmission projects have emerged. Pattern Energy Group, for instance, has recently unveiled an expansive $1 billion Southern Cross Project transmission proposal that would carry up to 3,000 MW of renewable power from Texas to the Southeast. The Southern Cross Project proposes an HVDC line connecting the AC lines developed as part of Texas' "competitive renewable energy zone" effort with AC lines in Mississippi owned by the Tennessee Valley Authority, Southern Company and/or Entergy over separate 500 kV lines.\textsuperscript{65}

Each of these projects is representative of the considerable transmission development efforts being accomplished nationwide, and further illustrates the investment being made in regional and interregional transmission projects and, in particular, projects designed to integrate renewable resources. These projects are being developed or planned under existing regulatory

\textsuperscript{63} Id., 25.
\textsuperscript{64} Id., 64.
structures and without the need for additional incentives. FERC itself acknowledged this in its NOPR and recognized that "a trend of increased investment in the country's transmission infrastructure has emerged in recent years." Yet at the same time the NOPR severely underestimates the extensive investment in transmission projects in the aggregate and into the future, and substantially overlooks regional and interregional projects that are being advanced without the socialization of costs.

LPPC members report that the experience of EEI's members is typical of what has occurred industry-wide. As will be reported in comments filed by LPPC members in the West, transmission developments in which LPPC members are participating are proceeding apace, while LPPC members in the Southeast are pleased to note that the region has been given a stellar report card by the Department of Energy ("DOE") for recent transmission development. In December of 2009, DOE concluded that there is little economic or reliability congestion in the Southeastern United States "[b]ecause the Southeastern utilities build aggressively in advance of load." And this system should remain robust, as SERC members have invested approximately $1.9 billion in new transmission lines and system upgrades 100 kV and above in 2009 and plan to spend approximately $2.4 billion in 2010 and approximately $2.3 billion in 2011.

66 NOPR at P 33, n.41.
C. Cost Subsidization for Long-Line Transmission Development Tilts the Balance in Determining how to Meet Renewable and Carbon Control Goals, and will Engender Needless Controversy, Ultimately Impeding Project Development.

The call for regions, and perhaps for multiple regions, to spread the cost of new transmission facilities to all load effectively asks that resources requiring long-line transmission facilities be provided an enormous subsidy. As load-serving entities search for resources to meet load requirements and various policy initiatives (including state or federal RPS, or carbon control requirements), such subsidization will foreclose reliance on otherwise economic alternatives, needlessly increasing costs to consumers, while risking substantial stranded costs in the event remotely-located resources prove to be uneconomical despite their subsidization. Further, cost subsidies undermine the discipline present when a project developer must ensure that there is market support for its project. Market discipline is critical in ensuring that investments are undertaken efficiently, balancing the nominal cost of the project and alternatives, against location and the associated transmission cost. Transmission subsidies skew that decision-making.

Building transmission to access remotely located renewable resources is only one of many means by which utilities may respond to requirements to reduce greenhouse gases ("GHGs"). Studies by the Electric Power Research Institute ("EPRI") (the "Full Portfolio" analysis) and by McKinsey and Company in its 2007 "U.S. Greenhouse Abatement Mapping Initiative" show a wide variety of options that may be employed in meeting GHG reduction, including: energy efficiency initiatives (many calling for capital investment); conversion of existing generation to more efficient operations; the development of additional nuclear capability; advanced coal generation and carbon capture and storage; distributed renewable
resources (including distributed solar); plug-in hybrid vehicles and the development of large-scale remotely located renewable generation.69

State-based RPS requirements, and potentially a federal RES or carbon control regime, will provide utilities with a powerful incentive to employ all available options for GHG emission reductions. Of course, many utilities will make plans to build new transmission facilities in order to access remotely located renewable resources, while project developers will have reason to invest in such facilities in order to access newly motivated markets. But socializing the cost of that transmission will tilt the playing field dramatically away from any alternatives that do not depend heavily, or at all, on transmission. If the substantial cost of transmission to remote resources is forced upon all load, it will be, to use an economist's term, sunk cost, and alternatives to meeting carbon control requirements will be far less economical by comparison. This will have the effect of crowding out more cost-effective investment in other means of satisfying environmental goals, including the reliance on local renewable resources. LPPC notes, e.g., that JEA, an LPPC member, has made a significant commitment to solar energy, agreeing to purchase the full output of a 12.7 MW central station solar photovoltaic plant under construction in Jacksonville, Florida from 2010 through 2040. Heavy transmission subsidies for other forms of remote renewable energy may very well have undermined this project, and the nascent solar industry in the Southeastern U.S.

LPPC adds that it seems quite probable that the mandatory socialization of transmission costs may very well have the unintended effect of inhibiting transmission development. That is why it is critical for the Commission to adhere to the cost causation principles articulated in ICC

It is evident that transmission development has picked up in the past few years, as the Commission itself notes. To the extent this transmission is planned to span utilities and/or RTOs, current plans call for it to be paid for by entities planning to use the facilities or otherwise handled through existing rate structures. Logically, if the Commission eschewed cost causation principles, project developers and potential customers would hold out for subsidized treatment. Complicating matters further, there is every reason to believe that with the potential for cost socialization, the planning process will become vastly more contentious, slowing down needed projects, as parties who do not see themselves benefiting from facilities, but nonetheless fear bearing the related costs, seek to thwart the projects, even as other entities seek to ensure that costs they might otherwise agree to incur themselves are offset by regional contributions.

The Commission’s affirmance of the cost causation principle notwithstanding, the Commission appears to suggest that, to prevent what it refers to as “free ridership,” costs can nonetheless be allocated to parties based on the theoretical benefits they receive – even absent a customer/provider relationship. This is a solution in search of a problem. LPPC cannot agree with the Commission that cost socialization is needed, much less permitted, in order to protect against the inequities of perceived “free ridership,” a concept that the Commission takes to refer to the relatively cost-free transmission that may be provided to entities who take advantage of others' oversized investments. It is self-evident that this concern comes with an existing set

70 NOPR at P 33, n.41.
72 NOPR at P 142, 168.
73 Id. P 142, 168.
of ready solutions, including a Commission determination that such late-comers will bear a portion of the initial investors' capital costs. Alternatively, the creation of a robust secondary market permitting the recovery of capital costs will address this issue.

Finally, LPPC points out that the NOPR's proposal is completely at odds with the manner in which the Commission approaches new interstate gas pipeline developments. In fact, all such projects are self-sustaining, and do not derive any subsidization from existing services. As is economically appropriate, such projects are sustainable and supported by sufficient demand to justify the project developers' costs. This approach is also consistent with the Commission's current approach to independent electric merchant transmission development.

D. There is No Lawful Mechanism for Allocating Costs to Entities without a Service Relationship and Contractual Privity Between the Transmission Provider and its Customers.

The Commission's proposal to establish a mechanism through which transmission developers would recover costs from entities to whom they provide no transmission service is without precedent and unlawful. To begin with, LPPC notes that the Commission's reference to such a mechanism as involving "cost allocation" is a misnomer. In traditional ratemaking parlance, cost allocation involves the process of determining the appropriate portion of a utility's cost of service that will be borne by each class of customers. Importantly, the exercise

74 See, e.g., Northern Border Pipeline Co., 90 FERC ¶ 61,263 (2000); Williams Natural Gas Co., 79 FERC ¶ 61,055 (1997); Natural Gas Pipeline Co. of America, 76 FERC ¶ 61,142 (1996).


presumes that all entities to which costs are so "allocated" are customers of the utility performing the allocation. This is no less true of allocations on RTO/ISO systems (transmission providers in a direct relationship with their customers), than it is of vertically integrated utilities outside the RTO/ISO framework.

By contrast, the NOPR appears to contemplate a mechanism that would enable transmission developers to recover their costs from entities with whom they have no service relationship. The only nexus the Commission seems to foresee between the transmission developer and the entity to which costs are "allocated" is some showing of minimal conferred benefits, perhaps through the expectation that service may be taken on such facilities, even if service is not in fact provided. This, the FPA does not permit.

The FPA is structured on the assumption that rates subject to FERC approval are supported by a contractual agreement or tariff to take and provide service between a utility and its customers. Utilities filing for rate changes under FPA section 205 ask the Commission to approve changes in rates charged to their customers. Likewise, the Commission is authorized under FPA section 206 to direct utilities to charge revised rates to their customers if existing rates are found to be unjust and unreasonable. But the Commission's authority is, in all cases, based on the premise that a utility has a contractual and/or tariff relationship to provide service to its customers. Long-established Supreme Court precedent in the Mobile-Sierra cases supports this view. Commenting on that premise in Borough of Lansdale v. FPC, 494 F.2d 1104, 1113 (D.C. Cir. 1974), the court held that the purpose of the Mobile-Sierra doctrine is "to

subordinate the statutory filing mechanism to the broad and familiar dictates of contract law." It is, accordingly, well outside the Commission's authority to attempt to devise a mechanism whereby transmission developers would attempt to recover their costs from entities with whom they have no contractual or tariff relationship. 

The Commission's attempt to defend its proposal on the ground that it routinely assesses costs to entities which do not agree to shoulder them voluntarily\(^{78}\) misses the point entirely. Of course, the Commission routinely sets rates that will be paid by customers that do not agree the rates are justified. But what distinguishes the proposal in this docket from all such cases is that the Commission routinely sets rates that will be charged by utilities to their customers. And even then, as the Supreme Court held in *Mobile-Sierra*, rate changes are further limited to the extent rates are subject to the parties' contract. Here, the Commission contemplates no such service relationship or contractual privity.

Nor does the Commission's reference to cases in which it has suggested a willingness to entertain filings for the recovery of costs associated with parallel path flow provide support.\(^{79}\) As the Commission itself indicates in the very same breath, it has *never* accepted such a filing, and has instead indicated that its general policy is to "encourage owners and controllers of transmission facilities to attempt to resolve parallel path flow issues on a consensual, regional basis."\(^{80}\) Of course, LPPC has no quarrel with the Commission encouraging parties to enter into mutually beneficial cost-sharing arrangements voluntarily. And LPPC can envision that regional planning fora may present an opportunity for parties to discuss such arrangements. But

\(^{78}\) NOPR at P 142.

\(^{79}\) *Id.*, P 143.

\(^{80}\) *Id.* (citing Southern California Edison Co. 70 FERC ¶ 61,087 at 61,241-42 (1995)).
what the Commission cannot do is foist transmission developers' costs involuntarily upon entities which choose not to take service from those developers.

The Commission's reference to its decision in *Midwest Indep. Transmission Sys. Operator, Inc.* 109 FERC ¶ 61,168 at P 60 (2004) is equally unsupportive. There, the Commission directed the Midwest ISO and PJM to develop a methodology for allocating costs between the RTOs reflective of the fact that facilities built in one RTO may benefit customers in the other, who transmit power through both. The Commission cites the case for the proposition that costs incurred by one transmission operator may be allocated to another transmission operator on the strength of the fact that benefits are conferred. Yet, in that case, the resulting structure called for the ultimate transmission customers to be in contractual privity with both ISOs, while the mechanism for allocating costs between the ISOs (for eventual recovery from their customers) was a Joint Operating Agreement ("JOA"), through which costs were voluntarily shouldered by the ISOs. The case is, accordingly, wholly inapposite to the proposal on the table here, whereby the Commission suggests that it has the authority to permit transmission developers to allocate costs to unrelated entities with whom there is no contractual relationship, on the strength of a determination of presumed benefits.

---

81 *Id.* P 144.

82 *Id.*

83 The Commission asserts at NOPR P 144, n.156 that the JOA between MISO and PJM was irrelevant to its authority. According to the Commission, it "did not base the …directive on the existence of the Joint Operating Agreement, which Midwest ISO and PJM developed in order to comply with a previous Commission directive. *Id.* (citing Alliance Cos. 100 FERC ¶ 61,137, at P 48 (2002)). But the relevance of the voluntary nature of the JOA on this topic cannot be so quickly dismissed. In fact, at P 60 of 109 FERC ¶ 61,168, the Commission states: "We note that in their Joint Operating Agreement, the Midwest ISO and PJM have committed to develop such a methodology for allocating the costs of certain facilities…" Accordingly, the Commission's authority in this connection was not subject to challenge.
Finally, LPPC finds entirely unavailing the Commission's citation to the court's decision in *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004). The Commission cites the case for the proposition that "...courts have affirmed that the cost causation principle allows the Commission to allocate at least some types of costs to beneficiaries that are not customers of the public utility that is seeking to recover the costs in question." At issue in that case was the Commission's determination that Midwest ISO transmission owners should bear an administrative cost associated with the ISO's management of the transmission owners' bundled and grandfathered loads (and not only unbundled load). But the central point the Commission seems to miss in its reference to the case is that the Midwest ISO transmission owners are customers of the Midwest ISO. For that reason, what was before the Commission and the courts was a traditional cost allocation matter – *viz.*, the appropriate level of cost to be allocated a utility's customers, based on the benefits conferred. What the Commission is now contemplating, by contrast, is the distribution of costs to entities with no contractual relationship with the transmission developer.

E. **Assuming, Arguendo, that Costs Can be Distributed Without Regard to a Service Relationship, an Allocation of Costs Based on "Benefits" Must Nonetheless be Consistent with FERC's Statutory Authority.**

Putting to one side the foregoing discussion regarding the necessity of a contractual relationship, LPPC is heartened to see in the NOPR the Commission's recognition that its own decisions and those of the courts "...have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the 'cost causation' principle." LPPC urges the Commission to be clear, however, regarding the nature of the benefits that will justify

---

84 NOPR at P 146.
85 *Id.* P 139.
an allocation of costs, and on the necessary strength of the nexus between rates and benefits.

LPPC is concerned that the Commission seems not to have set its sights higher than a
determination that costs allocated to a beneficiary are "roughly commensurate" with benefits.

As to the nature of the benefits that the Commission may recognize in allocating costs,
the Commission must acknowledge that the FPA limits its consideration to economic and
reliability factors. These considerations – and none broader – are evident on the surface of the
statute. FPA sections 205 and 206 authorize the Commission to set just and reasonable rates for
non-discriminatory, reliable service, and nothing more. FPA section 215, of course, establishes
a defined role for the Commission in connection with the promulgation and enforcement of
reliability standards. As discussed above (supra, p. 21-22), the Supreme Court in NAACP v.
FPC, 425 U.S. 662, has made it clear that the FPA "...is not a broad license to promote the
general public welfare," but must instead be read in light of the "principal purpose" of the
statute, viz., "to encourage the orderly development of plentiful supplies of electricity . . . at
reasonable prices." Id., 425 U.S. at 669-70. Moreover, as also discussed above, FERC has
itself held that its authority under FPA sections 205 and 206 does not extend to the
consideration of the environmental impact of its decisions. Accordingly, the benefits to which a
legitimate cost allocation mechanism must be tied relate exclusively an adequate and
economical supply of reliable electricity.

To be clear, LPPC recognizes that the demand for transmission facilities will reflect
customer needs which may very well be driven by environmental directives. Responding to a
state or federal RES, or potentially to a carbon control framework, the need for transmission to
access renewable resources may very well become a factor in transmission demand. But the
Commission must remain mindful that its mission lies in ensuring that the demand for

48
transmission service is met, regardless of the motivating factors. Accordingly, LPPC asks the Commission to confirm that the benefits relevant to any cost allocation methodology will relate exclusively to the availability of reliable transmission capacity at just and reasonable rates.

As to the strength of the nexus between rates and benefits, LPPC urges the Commission to be rigorous. The Commission draws the conclusion that costs need be no more than "roughly commensurate with benefits" from the decision in *ICC v. FERC*, in which FERC was faulted for failing to provide "even the roughest of ballpark estimates of...benefits" in support of its decision to roll into system-wide rates all new transmission facilities of 345 kV and larger. *ICC v. FERC*, 576 F.3d at 476. But the Seventh Circuit's rhetoric was designed to critique what the court took to be the Commission's cavalier attitude toward any needed evidence in support of its decision. While it is true that the courts have not required exactitude in the association of cost and benefits in support of a cost allocation mechanism, as the court in *ICC v. FERC* commented, the Commission has itself previously commented that "a claim of generalized system benefits is not enough to justify requiring existing shippers to subsidize [a new project]." LPPC respectfully suggests that assigning costs based on assertions of qualitative benefits and conjecture about the benefits of a new transmission facility over a period of decades would be speculative, and ultimately held to be arbitrary and capricious.

LPPC recognizes that in *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010), issued the same day as the NOPR, the Commission eschewed reliance on a "quantitative study" of benefits, in favor of cost allocation based on "qualitative" benefits, including alleged benefits that might accrue to a particular party decades in the future. LPPC urges the Commission to be

86 *Id.* P 76, 85.
more rigorous here. As the court in *ICC* held, one cannot simply assume that transmission facilities over a certain size are generally beneficial, without reasoned operational analysis.

**F. Interregional Cost Allocation (NOPR at PP 170 – 178)**

LPPC's concerns with the Commission's approach to interregional cost allocation are similar to those raised with respect to the proposal governing regional cost allocation, discussed above. LPPC is encouraged by: (1) the Commission's indication that it is not proposing a uniform approach to cost allocation;\(^{87}\) (2) the Commission's indication that a transmission planning region that receives no benefit from an interregional transmission facility that is located in that region must not be involuntarily allocated any of the costs of that facility;\(^{88}\) and (3) the Commission's indication that the cost of an interregional facility must be assigned only to transmission planning regions in which the facility is located.\(^{89}\)

LPPC also supports the Commission in embracing of cost causation principles, but disagrees strenuously with the Commission's view that costs may be assessed to LSEs by transmission developers based solely on the LSE's identification as ostensible "beneficiaries" of a transmission project, notwithstanding the fact that there is no service relationship between the parties. For reasons argued above, LPPC does not believe such an assessment would be lawful.

As a practical matter, LPPC sees immense complications in the Commission's proposal that "public utility transmission providers located in each pair of neighboring transmission planning regions develop a mutually agreeable method for allocating between the two transmission planning regions the costs of a new transmission facility that is located within both

\(^{87}\) NOPR at P 175.
\(^{88}\) *Id.* P 174.
\(^{89}\) *Id.*
regions and that is eligible for interregional cost recovery pursuant to the region's interregional transmission planning agreement...”90 LPPC envisions a planning process for interregional facilities driven with strife over cost allocation disputes, as parties seek, variously, to have their favored projects underwritten by others interregionally, or to evade such subsidization. Complicating that struggle is the fact that such discussions would take place in a factual vacuum – without reference to specific projects in the context of which the discussion might be given meaning with respect to the cost of potential facilities and their benefits.

Moreover, it is not at all clear how the Commission imagines that discussions "in each pair of neighboring transmission planning regions" will relate to one another. Indeed, there would be an interconnection-wide daisy chain of such discussions, all of which would have reverberations for one another, and all with complications of their own. Again, without reference to specific projects, LPPC sees the potential for endless debate. As difficult a matter as such discussion have been in the context of RTO operations (a subject with which the Commission has had recent and not altogether happy experiences), discussion among regions outside an RTO will inevitably be more complicated, as they involve utilities with disparate goals and needs, levels of investment, business models and regulatory masters.

In answer to all of this, LPPC urges the Commission to step back, in recognition of probability that the interregional allocation of costs is a topic on which consensus is feasible only in the context of specific projects proposed by project developers in order to satisfy identified market needs. Planning and cost allocation discussions are far likelier to result in the construction of necessary and efficiently utilized facilities when they reflect market pull, and

90 Id. P 172
not a regulatory push. The Commission's interest in having regions develop cost allocation principles in advance of such proposals puts the proverbial regulatory cart before the horse.

LPPC further adds that its members cannot at this time commit to entering into interregional agreements regarding cost allocation, for the reasons similar to those articulated above with respect to arguments regarding transmission planning.\(^91\) LPPC members will commit to participate in interregional discussions in order to develop a cost allocation mechanism. But without knowing what commitments and liabilities such agreements may include, LPPC members simply do not have the authority to commit their companies to an open-ended funding mechanism. As noted above, LPPC members are creatures of state and municipal governments, created by statute or municipal ordinance, and their authority to enter into binding arrangements is closely restricted consistent with their fiduciary responsibilities, and in a manner that will protect state and municipal sovereignty. LPPC members are restricted in their contracting practices by covenants in their financing arrangements, and cannot volunteer to enter into agreements that would, among other things, violate or jeopardize a private activity bond rule for purposes of section 141 of the Internal Revenue Code of 1986, 26 U.S.C. § 141, or any successor statute or regulation. With this in mind, LPPC members cannot commit to enter into agreements at this time, and cannot do so until substantial additional definition and assurance is provided.

V. Compliance Filing Schedule

LPPC does not believe the Commission's proposed one-year deadline for the finalization of interregional transmission planning agreements and interregional cost allocation

\(^{91}\) See supra, p. 29-30.
methods is realistic, when one considers the amount of work and extent of coordination these tasks call for, and the level of controversy likely to accompany the effort. These processes are likely to be particularly contentious if the Commission hews to its current proposal to reject approaches to regional and interregional cost recovery based on a requestor-pays approach. But even if that issue is resolved, the one-year deadline is substantially too aggressive. LPPC recommends that the Commission call for status updates on these matters in one year's time, potentially to be followed by further orders on a regional basis establishing a further reasonable timeline.

VI. The NOPR's Lack of Clarity in Several Key Areas Violates the Administrative Procedure Act.

In certain key respects, each addressed above, LPPC is concerned that the proposals in the NOPR do not provide clear indication of the Commission's intention. This is true in the following areas:

- It is not clear whether FERC proposes that regional and interregional plans will serve as the basis for future orders requiring utilities to undertake construction consistent with the plans. See supra, p. 16-19.

- It is not clear whether FERC proposes that regional and interregional plans would serve as the basis for orders compelling utilities to defer to non-incumbent utilities in connection with the construction of facilities needed for reliability purposes. See supra, p. 23-29.

- It is not clear what public policies must be incorporated in transmission plans, or in what manner such policies should be reflected. See supra, p. 19-21.

- It is not clear what rate mechanism FERC would employ to "allocate" costs incurred by non-incumbent transmission providers to entities with whom they have no service or contractual relationship. See supra, p. 43-47.

The Administrative Procedure Act, 5 U.S.C. § 553 ("APA") requires the Commission to provide notice of proposed rules adequate to afford interested parties a reasonable opportunity to participate in the rulemaking process. See Florida Power & Light Co. v. U.S., 846 F.2d 765,
771 (D.C. Cir. 1988). A notice of proposed rulemaking must provide sufficient factual detail and rationale to permit interested parties to comment meaningfully. See id. Where a notice of proposed rulemaking fails to provide an accurate picture of the reasoning that led an agency to its proposed rule, parties will not be able to comment meaningfully on the agency's proposals. Connecticut Light and Power Co. v. NRC, 673 F.2d 525, 530 (D.C. Cir. 1982) ("CL&P").

VII. Municipal Participation in Transmission Planning and Cost Allocation

A. LPPC Members will Commit to Participate in Regional and Interregional Planning Processes, and in Regional and Interregional Cost Recovery Mechanisms where they Fairly Reflect Benefits Received.

Consistent with the commitments LPPC members made in connection with the implementation of Order No. 890, LPPC members commit here to participate in regional and interregional planning fora instituted pursuant to a rulemaking in this docket. As described at some length above, LPPC members are already participating extensively in the Order No. 890 regional processes, and are an intimate part of the broader interregional and interconnection-wide efforts already under way through EIPC and WECC auspices. Further, LPPC members will participate actively in regional and interregional discussions regarding proposals for transmission cost recovery. But, as also indicated above (supra, p. 29-30, 50-52), LPPC members cannot now commit to enter into binding agreements on these subjects.

As to the cost allocation mechanisms the Commission proposes to require, LPPC members will commit to consider any regional and interregional proposals that are advanced in regions of the country in which they do business. But they cannot agree now, without specific information identifying the costs and benefits associated with a given project or set of projects, to commit to funding. Such an open-ended commitment would violate the independent fiduciary responsibility LPPC members have shouldered on behalf of their customers.
B. Reciprocity Cannot be Expanded to Require Participation in Mandatory Region-Wide Cost Sharing, or to Require Municipalities to Alter Plans Deemed Necessary to Meet their Service Obligations.

At NOPR P 43, the Commission asserts that it "expects all public utility and non-public utility transmission providers to participate in the regional transmission planning and cost allocation processes proposed by this Proposed Rule." The Commission refrains from asserting its authority under FPA section 211A, but states that:

Reciprocity dictates that non-public utility transmission providers that take advantage of open access, including improved regional transmission planning and cost allocation, should be subject to the same requirements as public utility transmission providers.

At NOPR P 181, the Commission

…proposes that transmission providers that are not public utilities would have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their Safe Harbor tariff or otherwise satisfying the reciprocity requirements of Order No. 888 [citation omitted].

This requirement would expand dramatically the commitment that non-public utilities were asked to make pursuant to the reciprocity provisions in Order No. 888 and ensuing orders. It would also exceed the Commission's authority. As initially conceived in Order No. 888, reciprocity was thought to be a matter of fundamental fairness. As the Commission described it in Order No. 888-A: "It would not be in the public interest to allow a non-public utility to take non-discriminatory transmission service from a public utility at the same time it refuses to provide comparable service to the public utility."92 In Order No. 2004-A, the Commission clarified that that the service provided by a non-public utility need not be identical to the service

provided by an investor-owned utility, but rather need only be comparable to the service the non-public utility enjoyed for its own purposes.  

With the enactment of FPA section 211A, this conception of the "comparable service" the Commission is authorized to require has been written into law. FPA section 211A provides that the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services —

   (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and

   (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.

It is quite clear that this authority does not permit the Commission to compel a non-public utility to contribute funding for regional or interregional transmission projects, nor would it enable the Commission to exercise any authority over the transmission planning or construction plans of a non-public utility. Instead, the statute makes it plain that the Commission's authority is limited to compelling a non-public utility to provide transmission service, at rates and on terms and conditions that are essentially inward looking. One must ask how the service is provided by the utility to itself in determining the utility's obligation to third parties.

With this highly defined and circumscribed authority directly expressed by statute, the Commission does not now have the option of redefining the terms under which reciprocal service is provided in a manner that would give the Commission broader authority than Congress has directly provided. It is well-established that the Commission may not do

93 Order No. 2004-A, 106 FERC ¶ 61,220, at P 775 (2004). This view of "comparability" is the manner in which the open access tariff under Order No. 888 was initially conceptualized.
indirectly what it may not do directly. Accordingly, LPPC does not see that the Commission has the authority to compel non-public utilities to contribute to new regional or interregional cost allocation mechanisms, or to operate according to FERC-approved transmission plans directing the level and nature of transmission investment.

VIII. CONCLUSION

LPPC urges the Commission to craft the final rule in this proceeding, consistent with the foregoing argument.

Respectfully submitted,

/s/ Jonathan D. Schneider
Jonathan D. Schneider
Jonathan P. Trotta

STINSON MORRISON HECKER LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036
JSchneider@stinson.com
JTrotta@stinson.com
(202)785-9100

Attorneys for the
Large Public Power Council

September 29, 2010
Washington, DC

94 Sunray Mid-Continent Oil Co. v. FPC, 364 U.S. 137, 152 (1960); National Fuel Gas Supply Corp. v. FERC, 909 F.2d 1519 (D.C. Cir. 1990).
ATTACHMENT

PLANNING PROCESSES IN THE EASTERN AND WESTERN INTERCONNECTIONS TO WHICH LPPC MEMBERS ARE PARTIES.
Planning Processes in the Eastern and Western Interconnection to Which LPPC Members are Parties

In all regions of the nation in which LPPC members operate, processes are already in place or under development that address concerns highlighted in the NOPR and the Commission's interest in ensuring that needed regional and interregional transmission projects are studied and developed. The NOPR identifies alleged deficiencies in transmission planning without which the construction of new transmission facilities could be inhibited. The Commission also highlights a perceived lack of coordination between transmission planning regions, adding that more efficient transmission solutions may be identified through regional planning than through independent evaluation by transmission providers. While LPPC agrees with the Commission that coordinated transmission study and development is important, the NOPR appears to underestimate the extent to which transmission projects are presently being studied and developed on a regional level throughout the nation. In particular, LPPC members are taking meaningful steps to improve interconnection-wide transmission planning in order to facilitate the development of transmission facilities designed to interconnect new generation resources, and LPPC supports efforts already underway in both the Western and Eastern Interconnections that engage all stakeholders in regional planning. These coordinated efforts in each of the LPPC members' regions are detailed below.

A. Eastern Interconnection Transmission Planning

1. Coordinated Transmission Planning Processes in the Southeast

95 NOPR, P 35.
96 Id. P 39.
The Southeast has adopted a bottom-up transmission planning process that is driven primarily by State-regulated Integrated Resource Planning ("IRP") (including related mandatory Requests for Proposals ("RFPs"). These State-jurisdictional IRP and RFP processes first identify the electric system's incremental needs (e.g., load growth) and then determine the most cost-effective and reliable resource and transmission solutions for meeting the future needs of the utility's consumers. As a result, State "public policy" considerations are affirmatively included in the IRP/RFP processes in the Southeast.

In the Southeast, the primary State public policy driver for generation, distribution, and transmission expansion remains the State-imposed "duty to serve" requirement, which generally requires State-regulated public utilities to maintain and expand their system on a least-cost and reliable basis to meet the needs of consumers. These and other public policy considerations are taken into account during the State-regulated IRP/RFP processes and are thereby embedded into transmission plans.

The results of a utility's State-regulated IRP/RFP process are combined with other firm transmission service commitments made by a utility's customers. This results in development of a transmission plan that accounts for a transmission owner's service to its native load and other firm transmission service commitments on its transmission system. Service requests made by a utility's customers represent decisions on how to best meet future energy needs, including those needs driven by federal and State "public policy" requirements, in an acceptable, least-cost fashion.

Once a utility has planned its system to accommodate the results of the IRP/RFP processes and its customers' OATT service requests, these results largely become the data inputs
for each utility's respective regional transmission planning process required by Order No. 890.

Some utilities in the Southeast incorporate the results of the IRP/RFP and OATT processes into the Southeastern Regional Transmission Planning Process ("SERTP"),\(^97\) which, like the other regional planning processes in the Southeast, is a coordinated, open and transparent planning process that provides stakeholders with the opportunity and information to participate and confirm that regional transmission planning is being conducted on a non-discriminatory and comparable basis. Through the SERTP, the results of the underlying utilities' IRP/RFP and OATT processes are coordinated and combined to develop a transmission expansion plan for the entire SERTP region. Other regions in the Southeast construct similar regional transmission plans pursuant to their regional processes.

If any neighboring planning process may be impacted by a planning criteria identified in such a regional planning process, the potentially impacted region/transmission planning authority is contacted to determine if there might be a need for an interregional, *ad hoc* coordination study between the affected regions. If the neighboring region agrees that it would be impacted by the projected limitation, a specific interregional coordination study is initiated. Once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the regions' transmission expansion plan.

Once the SERTP plan and other Southeast regional transmission plans are completed, the SERC Reliability Corporation's ("SERC") transmission planning committee (which is composed of representatives from the transmission-owning and operating utilities in the Southeast) analyzes the various sub-regional and regional transmission plans to facilitate

\(^{97}\) The SERTP was a pre-existing regional transmission planning process that several Southeast utilities used to comply with Order No. 890's Attachment K planning requirements.
simultaneous interregional feasibility and consistency in models and data. This SERC-wide
analysis effectively rolls the regional transmission plans into a set of unified, interregional
SERC transmission base cases. If the SERC-wide reliability model projects additional concerns
that were not identified in the underlying regional studies, then the impacted transmission
owners may initiate one or more ad hoc interregional coordination studies to better identify the
projected concern. The resulting reliability enhancements that might be identified are then
incorporated into the affected region's expansion plan. "Accordingly, concerns identified at the
SERC-wide level are 'pushed-down' to the transmission owner level for detailed resolution." 
Transmission planners in the Southeast further coordinate on an annual basis with the other
NERC Regional Entity transmission planners and planning authorities in the Eastern
Interconnection to produce the interconnection-wide, NERC Eastern Interconnection Reliability
Assessment Group ("ERAG") Multiregional Modeling Working Group ("MMWG") base cases
that provide the foundation for essentially all subsequent transmission planning studies in the
Eastern Interconnection.

Regional planning processes throughout the Southeastern are further integrated through
the Southeast Inter-Regional Transmission Participation Process ("SIRPP"), an annual process
developed by Southeast transmission providers to more fully address Order No. 890's regional
participation principle. SIRPP complements the regional planning processes of participating
transmission owners in the Southeast by consolidating data and assumption developed at the
regional level and using that information to develop planning models. SIRPP ensures

98 While SERC provides the organizational/ committee structure that is used by the NERC-registered planning
authorities in its footprint to produce the annual SERC-base cases and also performs a long-term reliability
assessment for the SERC footprint, SERC itself performs no transmission planning.
99 The SIRPP was established pursuant to a request from FERC Commission Staff during the initial Attachment K
development process.
consistency in the planning data and assumptions used in local, regional and interregional planning processes.

SIRPP facilitates the development of economic planning studies that involve impacts on multiple systems between regional planning processes. Stakeholder requests for regional economic planning studies submitted through a SIRPP participant's Attachment K process that involves transmission providers across multiple interconnected systems, are consolidated and evaluated as part of the SIRPP. Stakeholders may also request interregional economic planning studies directly through the SIRPP. Coordination of interregional economic planning studies through SIRPP is conducted by a study coordination team comprised of participating transmission owner staff that develops study assumptions, performs model development and other coordination efforts with stakeholders and impacted external planning processes. The study process also involves developing solution options and evaluating stakeholder-suggested solution options, and developing a report upon completion of all studies. The final report(s) is distributed to all participating transmission owners and stakeholders. SIRPP establishes detailed time frames and procedures for coordination with stakeholders in the development of interregional economic planning studies that emphasize transparency in the SIRPP study process. SIRPP procedures also provide clearly-defined opportunities for stakeholders to comment and provide input regarding draft reports.

Equally important to planning in the Southeast, SIRPP enables participating transmission owners to review regional data, assumptions and assessments being performed on an interregional basis.

LPPC members of the Southwest Power Pool (“SPP”) Nebraska Public Power District (“NPPD”) and Omaha Public Power District (“OPPD”) are active participants in the planning

These regional and interregional planning processes are further supplemented by the Eastern Interconnection Planning Collaborative ("EIPC") and the Eastern Interconnection State Planning Coalition ("EISPC"), as discussed below.

2. Eastern Interconnection-Wide Planning: EIPC

The planning processes in the Southeast and throughout the Eastern Interconnection are further supported and coordinated through the EIPC – a broad-based, transparent and collaborative process initiated by a coalition of planning authorities representing the entire Eastern Interconnection. The EIPC was instituted to address any otherwise unidentified alternatives to improve the efficiency and effectiveness of interregional transmission upgrades, and allows states in the Eastern Interconnection to participate in interconnection-wide planning efforts. In addition, the EIPC, with input from EISPC and stakeholders, evaluates various future scenarios that can inform policy makers and stakeholders in their future decision-making pertaining to resource and transmission commitments.

The EIPC facilitates interconnection-wide planning efforts and enables inputs from various stakeholders including state and federal policy makers, consumer and environmental interests, transmission planning authorities, and market participants generating, transmitting or consuming electric energy within the Eastern Interconnection. The EIPC builds upon regional transmission expansion plans developed yearly by regional stakeholders and planning

100 The EIPC is the recipient of DOE funding.
authorities to provide a coordinated interregional analysis for the entire Eastern Interconnection. This interconnection-wide planning process is guided by an open and transparent stakeholder process.

The EIPC enables planning authorities in the Eastern Interconnection to model the impact on the grid of various policy options determined to be of interest by state and federal policy makers and other stakeholders. The EIPC ultimately produces an interconnection-wide review of existing regional plans and transmission options associated with various policy options. This information serves as critical inputs into regional processes that build into regional and sub-regional models the efficiencies and improvements identified in the EIPC process.

The underlying principle of the EIPC is that fully coordinated interconnection transmission analyses is best accomplished through an approach that builds and expands on existing regional processes and planning expertise. EIPC, then, directly addresses any concerns the Commission might have about a perceived lack of coordinated planning between regions and over the seams of existing planning regions throughout the Eastern Interconnection. LPPC supports this model for identifying and developing planning efficiencies across the entire Eastern Interconnection.

B. Western Interconnection Transmission Planning

The Western Interconnection has a long history of broad regional and interregional cooperation under the Western Electricity Coordinating Council ("WECC")\(^{101}\) umbrella.

\(^{101}\) WECC is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. In addition, WECC assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in its bylaws. WECC's service territory extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states.
Transmission planning and expansion throughout the Western Interconnection is coordinated through numerous regional and sub-regional planning groups ("SPGs") that conduct transmission planning on a more local, sub-regional basis (see Figure 1). In addition to their local transmission planning processes, LPPC members engage in joint regional transmission planning with other transmission providers and stakeholders throughout the Western Interconnection through their participation in, among other regional and sub-regional planning groups, WestConnect\(^{102}\) and its Colorado Coordinated Planning Group ("CCPG"),\(^{103}\) ColumbiaGrid, the California Transmission Planning Group ("CTPG") and, ultimately, WECC.

---

\(^{102}\) WestConnect is an unincorporated association composed of utility companies providing transmission of electricity in the southwestern U.S. The WestConnect footprint encompasses the state of Arizona, Colorado, New Mexico, Nevada, and parts of California, Texas, South Dakota and Wyoming. Three major sub-regional technical planning working groups operate within the WestConnect footprint: the Southwest Area Transmission Planning Group, the Sierra Sub-Regional Planning Group, and the Colorado Coordinated Planning Group ("CCPG").

\(^{103}\) The CCPG is a joint, high voltage transmission system planning forum for the purpose of assuring a high degree of reliability in the planning, development, and operation of the high voltage transmission system in the Rocky Mountain Region. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region of the WECC. See [http://www.westconnect.com/planning_ccpg.php](http://www.westconnect.com/planning_ccpg.php)
1. CCPG and WestConnect Coordinated Planning

LPPC members are active participants in the CCPG, a sub-regional process tasked with coordinating transmission planning information and sharing updated on active transmission projects. The CCPG sub-regional planning group provides an open forum where stakeholders interested in transmission system planning within the CCPG footprint can participate and obtain information regarding base cases, plans and projects, and provide input or express outstanding needs related to the transmission system. The CCPG promotes sub-regional transmission

---

planning and development to ensure that participants' transmission plans are coordinated to maximize use of the existing transmission system and identify transmission expansion alternatives that most effectively meet future needs.

Transmission providers participating in CCPG submit their transmission plans for inclusion in CCPG planning activities, and further support the CCPG process through development of study assumptions, supplying system data, execution of studies when available, and review of study results and reports. Transmission plans submitted by CCPG participants are coordinated within CCPG, incorporated into CCPG transmission studies and plans, and coordinated between neighboring sub-regional planning groups through the WestConnect transmission plan process.

The CCPG facilitates stakeholder participation in its sub-regional planning process both through stakeholder attendance at CCPG meetings and through direct input to transmission providers.

WestConnect provides to its members, including LPPC members participating in the CCPG, increased coordination of study efforts between all SPGs within the greater WestConnect planning area. WestConnect's transmission provider members coordinate and actively participate in the WestConnect planning process pursuant to defined objectives and procedures for regional transmission planning, and integrate their transmission plans with plans of other WestConnect participants into a single ten year regional transmission plan.

This process is achieved by coordinating, developing and updating common base cases, as needed, to be used for all study efforts within the SPGs, and ensuring that each plan adheres to the common methodology and format developed by the WestConnect SPGs. Transmission
providers also submit any studies and pertinent financial, technical and engineering data to CCPG for review and comment, which is then used within the WestConnect planning process.

Stakeholders participate in the WestConnect planning process through participation in public stakeholder meetings or by providing input to the transmission provider that is conveyed to WestConnect. Both WestConnect and CCPG have transparent processes for stakeholder input, available through their respective websites.

WestConnect's coordinated planning process promotes consistency in the data, assumptions and models used in SPG planning activities. SPGs within the WestConnect footprint, assisted by the WestConnect planning manager, coordinate with other Western Interconnection transmission providers and their SPGs through WECC's Transmission Expansion Policy Planning Committee ("TEPPC"), as discussed below.

2. ColumbiaGrid

LPPC members in the Pacific Northwest are active participants in ColumbiaGrid and, along with other members of ColumbiaGrid, are signatories to the ColumbiaGrid Planning and Expansion Functional Agreement ("PEFA"), which provides for sub-regional transmission planning among its members. ColumbiaGrid's transmission planning process is designed to facilitate a "single-utility" approach to transmission planning among its members, under which the transmission facilities of various transmission providers are planned as if owned by a single utility. ColumbiaGrid actively develops a single transmission plan for parties to the PEFA that own or operate transmission facilities, and annually performs a system assessment of the interconnected transmission systems in the Pacific Northwest that is focused on determining the ability of each transmission owner or operator to serve, consistent with all appropriate reliability standards and criteria, its network and native load obligations and other existing long-term firm
transmission obligations anticipated to arise over the ten-year planning horizon. If this process reveals a projected inability for a transmission owner or operator to meet its existing obligations over this planning horizon, ColumbiaGrid forms study teams to develop a plan to resolve the need. These study teams facilitate collaboration among transmission owners, operators and other interested parties, to study and plan on a coordinated basis various types of projects, as defined in the PEFA.

On a regional level, ColumbiaGrid coordinates with neighboring planning entities throughout the Western Interconnection through its active, ongoing participation in the WECC sub-regional and regional processes. ColumbiaGrid is a SPG in the Western Interconnection and coordinates with other SPGs and with WECC. As part of this process, ColumbiaGrid meets regularly with other SPGs in joint meetings held at least three times annually, that focus on reviewing and coordinating study activities, development of WECC base case assumptions and requests, sharing of planning information, and coordination of requests to WECC for economic studies. ColumbiaGrid's model for sub-regional transmission planning has resulted in a high degree of coordination among transmission systems in the Northwest, including LPPC members' systems. ColumbiaGrid's regional transmission planning process has vetted several transmission plans that impact the systems of multiple transmission providers and, as part of the sub-regional planning process, has formed study teams consisting of non-PEFA parties that develop focused transmission plans to address complex transmission issues in specific areas, such as the Puget Sound area in Northwest Washington. Specific transmission plans such as these are developed by teams open to all interested parties, regardless of whether they are ColumbiaGrid signatories.
3. **CTPG**

LPPC members in California are also participating in the CTPG, which performs technical studies using California's Renewable Energy Transmission Initiative ("RETI") conceptual transmission plan as a starting point to help identify transmission projects needed to meet state-wide renewable energy goals. The CTPG includes California transmission owners and operators and functions to coordinate statewide transmission planning in California. The CTPG is a forum for conducting joint transmission planning and coordination to meet the needs of California consistent with Order No. 890, as well as to develop a state-wide transmission plan to meet California's 33% by 2020 renewable portfolio standard goal. Similar to the SIRPP process in the Southeast, the CTPG is the result of ongoing discussions facilitated by FERC to address transmission needs. The CTPG develops annually a California transmission plan that incorporates the needs of its participants, and identifies opportunities for joint transmission development projects.

4. **Western Interconnection-Wide Planning**

WECC's role in regional and interregional transmission planning is one of coordination, facilitation and analysis. WECC coordinates regional planning activities with and among SPGs, state and provincial agencies, balancing authorities and transmission providers, and provides impartial information to planners and decision makers in the Western Interconnection. In this way WECC supports the Order No. 890 and 890-A planning principles for transmission providers in the Western Interconnection.

WECC coordinates planning in several ways, including developing interconnection-wide databases for transmission planning analysis such as power flow, stability and dynamic voltage stability studies, as well as databases for reporting the status of all planned projects.
throughout the Western Interconnection. WECC also coordinates planned and proposed projects through its Procedures for Regional Planning project review. The process of identifying transmission needs and evaluating the impact of potential transmission solutions within the WECC framework is managed by two distinct processes: (1) TEPPC's regional expansion planning, which conducts Western Interconnection-wide economic studies in a transparent and open stakeholder process; and (2) the Planning Coordination Committee's ("PCC") path rating process, which ensures that new projects will have no adverse impacts on existing facilities or approved projects.

The WECC TEPPC provides two main functions in the planning process. Firstly, the TEPPC assists to develop and maintain an interconnection-wide economic planning study database that is widely available throughout the West. Secondly, the TEPPC performs economic planning studies that include studying transmission customer high priority economic study requests as determined by an open stakeholder process at the TEPPC level. LPPC members participating in WECC's interregional planning process report that TEPPC's open-season study request process involves data and model validation work through workgroup meetings to ensure that information and modeling techniques are coordinated. TEPPC is further charged with assisting the Western Governors' Association\textsuperscript{105} Renewable Energy Zone Initiative.

TEPPC's planning activities quantify future transmission congestion based on load, resource, and transmission scenarios provided by stakeholders through an open-season study request process. Based on the identified congestion, TEPPC also examines the impact of

\textsuperscript{105} The Western Governors' Association is a non-partisan organization of 19 states and three U.S. territories in the western region of the United States, covering a wide range of policies including an energy and transmission initiative.
various transmission expansion scenarios. These activities and the resulting analysis serve as guidance for future transmission system needs. While TEPPC does not propose transmission projects, WECC provides information and analysis through its study process which further facilitates the evaluation of proposed solutions. This in turn provides information and inputs for regional and sub-regional processes. In this way, WECC supports a bottom-up/top-down approach to planning in the Western Interconnection that ensures that accurate, quality data and stakeholder-vetted assumptions and models are available for use in planning processes throughout the region.

As part of a bottom-up process, TEPPC gathers data through an open-season study request process, which is then coupled with data and models from multiple sources, including the WECC load and resource reporting activities, SPG plans, and state and provincial activities. In its top-down planning process, information gathered by WECC is analyzed in open TEPPC workgroup meetings, and then used to determine future possible transmission congestion and solutions. WECC then makes this information, and resulting analysis, publically available through reports, models and data files. This information and analysis ultimately forms the basis for transmission planning processes developed throughout the Western Interconnection.

WECC's transmission expansion planning processes are undergoing significant expansion and refinement to better evaluate the reliability implications of state renewable energy policies, proposed greenhouse gas reduction policies, and the changing mix of generation and demand side resources. By way of example, TEPPC has undertaken more sophisticated studies to better understand how transmission needs compare for various state renewable energy preferences (e.g., local preference versus least cost). In this manner,
interregional transmission planning throughout the West already incorporates policy-based needs and requirements into expansion plans, consistent with FERC's objectives.

The above comprehensive regional, sub-regional and interregional/interconnection-wide processes facilitate and promote effective stakeholder involvement and enable coordination among planning entities to provide consistency of data, assumptions and models being used in planning activities at all levels. Regional and sub-regional plans in the East are coordinated and evaluated actively at the regional level through bottom-up planning, and through the EIPC. In the West, these plans are coordinated and studied by all SPGs and at the WECC TEPPC level.

LPPC supports this regional, sub-regional and interregional approach to transmission planning, and believes that maintaining planning at these levels allows and will continue to allow for effective planning and coordination for future transmission development. Imposing a new framework on top of these already-existing structures would serve to thwart the coordinated progress being made to date, and would complicate regional and sub-regional planning efforts that are otherwise effectively coordinating, studying and implementing needed transmission solutions.
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation  )
by Transmission Owning and  )  Docket No. RM10-23-000
Operating Public Utilities  )

COMMENTS OF THE
LARGE PUBLIC POWER COUNCIL

Jonathan D. Schneider
Jonathan P. Trotta

STINSON MORRISON HECKER LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036
JSchneider@stinson.com
JTrotta@stinson.com
(202)785-9100

Attorneys for the
Large Public Power Council

September 29, 2010
Washington, DC
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation )
by Transmission Owning and ) Docket No. RM10-23-000
Operating Public Utilities )

COMMENTS OF THE
LARGE PUBLIC POWER COUNCIL

TABLE OF CONTENTS

I. Introduction and Executive Summary ..............................................................1
II. The Need for Reform (NOPR at PP 32 – 43) ..............................................5
   A. LPPC Urges FERC to be More Rigorous in its Proposed
      Findings and Holdings. .................................................................5
III. Proposed Reforms – Transmission Planning (NOPR at PP 44 – 120) ..............12
   A. Participation in Regional Planning Processes (NOPR at PP 45 – 54) .........12
      1. LPPC Members Have Committed to Regional and
         Interregional Planning Processes. ..............................................12
      2. FERC Must Not Turn Regional Plans into
         Mandatory Templates. .............................................................16
   B. Public Policy Driven Projects (NOPR at PP 55 – 70) .............................19
      1. It is Unreasonable to Mandate that Public Policy be Taken
         into Account in Transmission Plans Other Than to the Extent it
         Translates into Actual or Anticipated Transmission Demand. ............19
      2. FERC Does Not Have Jurisdiction to Consider Broad Notions
         of Public Policy under the Federal Power Act. ............................21
   C. Opportunities for Undue Discrimination against Non-incumbent
      Transmission Developers. (NOPR at PP 71 – 101) ...........................22
      1. LPPC Does Not Generally Object to FERC's Proposed Tariff
         Revisions Specifying Terms under Which Non-Incumbent
         Transmission Developers Will Participate in the Planning Process. ....22
2. FERC Orders or Rules Compelling Utilities to Defer to Non-Incumbent Transmission Developers in the Construction of Facilities Needed to Serve Native Load Would be Beyond its Jurisdiction. .................................................................23

D. Interregional Coordination (NOPR at PP 102 – 120) ............................29

1. LPPC Members Will Participate in Consensus-Based Interregional Planning Processes. .................................................................29

2. LPPC Members Cannot Commit to Entering FERC-Jurisdictional Agreements Containing Interregional Planning Protocols. ...........29

IV Proposed Reform - Cost Allocation (NOPR at PP 121 – 178) ..................30

A. Introduction ............................................................................30

B. The Commission Demonstrates No Basis for Generic Rate Reform and there is Substantial Evidence of Robust Transmission Development Without it. .................................................................33

C. Cost Subsidization for Long-Line Transmission Development Tilts the Balance in Determining how to Meet Renewable and Carbon Control Goals, and will Engender Needless Controversy, Ultimately Impeding Project Development. .......................................................................40

D. There is No Lawful Mechanism for Allocating Costs to Entities Without a Service Relationship and Contractual Privity Between the Transmission Provider and its Customers. .........................................................43

E. Assuming, Arguendo, that Costs Can be Distributed Without Regard to a Service Relationship, an Allocation of Costs Based on "Benefits" Must Nonetheless be Consistent with FERC's Statutory Authority. ......................47

F. Interregional Cost Allocation (NOPR at PP 170-178) ...........................50

V. Compliance Filing Schedule (NOPR at 179 – 181) ...............................52

VI. The NOPR's Lack of Clarity in Several Key Areas Violates the Administrative Procedure Act. .................................................................53

VII. Municipal Participation in Transmission Planning and Cost Allocation .........54

A. LPPC Members will Commit to Participate in Regional and Interregional Planning Processes, and in Regional and Interregional Cost Recovery Mechanisms where they Fairly Reflect Benefits Received. .................................................................54
B. Reciprocity Cannot be Expanded to Require Participation in
Mandatory Region-Wide Cost Sharing, or to Require Municipalities
to Alter Plans Deemed Necessary to Meet their Service Obligations. 

VIII. Conclusion

Attachment – Planning Processes in the Eastern and Western
Interconnections to Which LPPC Members are Parties.
I. Introduction and Executive Summary

These comments are submitted by the Large Public Power Council ("LPPC") in response to the Commission's Notice of Proposed Rulemaking ("NOPR"), issued in this docket on June 17, 2010, and the Notice Extending Comment Period, issued on August 10, 2010.

LPPC is an association of 24 of the nation's largest municipal and state-owned utilities. It speaks for the larger, asset owning members of the public power community.1

LPPC has long been a supporter of the Commission's open access framework under Order No. 8882 and ensuing Order No. 890.3 Although LPPC members are exempt from

---

1 Together, LPPC’s members own approximately 34,000 miles of transmission, representing nearly 90% of the transmission investment owned by non-Federal public power entities in the United States. LPPC’s members are Austin Energy, Chelan County Public Utility District No. 1, Clark Public Utilities, Colorado Springs Utilities, CPS Energy (San Antonio), ElectriCities of North Carolina, IID Energy (Imperial Irrigation District), JEA (Jacksonville, FL), Long Island Power Authority, Los Angeles Department of Water and Power, Lower Colorado River Authority, MEAG Power, Nebraska Public Power District, New York Power Authority, Omaha Public Power District, Orlando Utilities Commission, Plate River Power Authority, Puerto Rico Electric Power Authority, Sacramento Municipal Utility District, Salt River Project, Santee Cooper, Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Public Utilities.


Federal Energy Regulatory Commission ("FERC") jurisdiction for most purposes under section 201(f) of the Federal Power Act ("FPA"), 16 U.S.C. § 824(f), LPPC members providing significant transmission service themselves or through an RTO or ISO, and who own and/or operate transmission, committed nonetheless to offer open access service under publicly available Open Access Transmission Tariffs ("OATT"). Further, LPPC members have been voluntary participants in the regional planning processes set in motion under Order No. 890. In addition, and relevant to this docket, LPPC members have been leaders in the interconnection of renewable resources and have an avid interest in working to establish a framework that maximizes the reliable and economical integration of these resources into grid operations.

LPPC agrees with the Commission that further steps may be taken to advance regional planning and interregional coordination, but believes the Commission should be much encouraged by the additional work already underway through existing regional and interregional planning fora. It is not clear to LPPC that the Commission fully appreciates the extent to which this work is already being undertaken, as is discussed below. LPPC strongly supports FERC's inclination to encourage solutions that are developed by stakeholders within regions. Very substantial differences in electric systems across the nation require differing approaches to planning and cost allocation for new transmission facilities. The differences

---

4 See LPPC, Initial Comments of the in Response to Notice of Proposed Rulemaking, Docket Nos, RM05-25, et al., at p.15-17 (filed Aug. 8, 2006) ("LPPC Initial Comments"). This commitment was reflected in Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 418-602. LPPC members offering transmission service under such tariffs include: Austin Energy, Clark Public Utilities, Colorado Springs Utilities, CPS Energy (San Antonio), IID Energy (Imperial Irrigation District), JEA (Jacksonville, FL), Long Island Power Authority, Los Angeles Department of Water and Power, Lower Colorado River Authority, MEAG Power, Nebraska Public Power District, New York Power Authority, Omaha Public Power District, Orlando Utilities Commission, Platte River Power Authority, Puerto Rico Electric Power Authority, Sacramento Municipal Utility District, Salt River Project, Santee Cooper, Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Public Utilities

5 See LPPC Initial Comments at 26-27. For LPPC members within RTOs, planning is undertaken in conjunction with that RTO's activity. This is true of the Long Island Power Authority ("LIPA") and the New York Power Authority ("NYPAP"), both New York ISO ("NYISO") members, and Nebraska Public Power District ("NPPD"), a transmission-owning member of the Southwest Power Pool ("SPP").
relate to: (1) variances in RPS requirements across the states; (2) differences in the resource base and availability of renewable resources; (3) business models and market structure; and (4) the existing state of transmission infrastructure development. For these reasons, FERC is right to focus attention on regional developments, and not to impose a super-regional or interconnection-wide planning model on the nation.

LPPC urges the Commission to avoid imposing mandatory planning templates on regions. LPPC supports the Commission's determination not to "dictate which investments" should be undertaken by transmission providers. However, LPPC is concerned that the Commission's proposal to require public utilities to file criteria to evaluate proposed transmission lines, and the proposed directive to each region to develop a single transmission plan (as opposed to engaging in an open process), may amount to the same thing.

Transmission construction and siting are state-jurisdictional matters, and most transmission investment is undertaken by utilities in order to serve their native load. Outside RTO regions, that investment finds its way principally into rates for bundled sales regulated by state commissions or otherwise set at the local level. The fundamentally state-based nature of this investment is underscored by FPA section 217(b) ("Native Load"), which directs FERC to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load serving entities."

With respect to the role of non-incumbent transmission developers, LPPC embraces the proposal to include these entities in regional and interregional planning processes. However, as to the role that these developers may play in developing facilities employed by load-serving entities.

6 NOPR at P 51, n.59.
entities to serve native load, LPPC asks the Commission to ensure that nothing in the NOPR would impede incumbent utilities in taking all steps necessary, including siting facilities, to meet their service obligations. LPPC disagrees strenuously with the Commission's premise that non-incumbent transmission developers are entitled to the FPA's protection against undue discrimination. The FPA protects customers from discrimination, not competitive transmission developers, as argued below. Furthermore, even if one assumed, for the sake of argument, that the protection against discrimination is applicable, the differences between transmission development needed by load-serving entities to meet their service obligations and for-profit transmission developers with a completely different set of obligations and goals amply justify differences in treatment. Nor does the Commission compile any significant record of discrimination.

As to cost allocation, LPPC believes the Commission has been wise to steer clear of calls for it to mandate interconnection-wide cost sharing. Further, the Commission is right to recognize that its precedent and governing legal authority require that it honor cost causation principles. As well, LPPC supports FERC's view that each region should approach cost allocation in a manner that suits its needs. LPPC members commit to participating actively in all regional and interregional discussions regarding cost allocation for new transmission facilities.

However, LPPC objects to the Commission's tentative determination not to accept regional cost recovery mechanisms that provide for funding of regional facilities exclusively though a "participant funding" mechanism, by which LPPC takes the Commission to mean a mechanism which assesses costs to those customers opting to use the facilities.\(^7\) LPPC does

\(^7\) Id. P. 168.
not agree that the Commission has the authority to establish a recovery mechanism for the cost of new transmission facilities across a region or between regions without respect to whether customers have a service relationship with the transmission developer. In the absence of an agreement by the customer to take transmission service from a service provider that has included the cost of such new facilities in its rates, LPPC sees no legal basis for cost recovery under the FPA. LPPC believes the Commission's proposal would be: (1) a mistake as a matter of policy; (2) inconsistent with governing rate setting precedent; and (3) outside the law, to the extent it purports to assess costs without a service relationship between transmission developers and a customer. LPPC further believes FERC's proposed approach would raise costs to consumers, unjustifiably subsidize selected (and not all) segments of the renewable supply industry, and mire the progress now being made in transmission development in needless controversy and litigation.

Complicating matters further, there is every reason to believe that with the potential for cost socialization, the planning process will become vastly more contentious, slowing down needed projects, as parties who do not see themselves benefitting from facilities, but nonetheless fear bearing the related costs, seek to thwart the projects, even as other entities seek to ensure that costs they might otherwise agree to incur themselves are offset by regional contributions.

II. The Need for Reform (NOPR at PP 32 – 43)

A. LPPC Urges FERC to be More Rigorous in its Proposed Findings and Holdings.

Summarizing its tentative decision at the outset of the NOPR, the Commission comments that:

The proposed reforms are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better
support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.\(^8\)

These conclusions call for factual determinations that must be supported by substantial evidence. The Commission is not given a free pass with respect to the evidence necessary to support generic orders governing structural industry changes, and it has been reversed on several occasions for failing to marshal sufficient support. Most recently, in *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006) ("*National Fuel*")\(^8\), the court found that FERC "provided no evidence of a real problem" to support changes in Order No. 2004 to rules governing standards of conduct, adding that the Commission instead relied on a "theoretical potential for abuse" by non-marketing affiliates. *Id.*, 468 F.3d at 841 (emphasis in original). According to the court, the information relied on by FERC included "mere restatements" of the alleged threat the Commission sought to remedy, and did "not constitute record evidence of abuse." The court went on to state that "[p]rofessing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making."\(^9\)

Similarly, in *Assoc. Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1985) ("*AGD*"), in reviewing FERC's rationale in Order No. 436 for industry-wide contract demand adjustment conditions, the court concluded that the Commission "failed to develop an adequate rationale in support of" its regulations. *Id.*, 824 F.2d at 1018. The court went on to state that FERC's justifications "seem peripheral to the problem the Commission set out to solve in [its] rulemaking." *Id.*, 824 F.2d at 1019. Further, the court held that the Commission's arguments

\(^8\) NOPR at P 1.

applied only "to a limited portion of the industry," and "hardly support[ed] the broad remedy adopted." *Id.* Based on the evidence presented in Order No. 436 and related precedent, the court concluded there was no support for "an industry-wide solution for a problem that exists only in isolated pockets." The court concluded that "the disproportion of [FERC's] remedy to ailment" rendered the order arbitrary and capricious. *Id.*

Here, as in *National Fuel* and *AGD*, the support FERC marshals for sweeping industry-wide change is quite thin, comprising just seven pages of conclusory material, at NOPR P 32-41. The entire substance of the Commission's ostensible evidence, and LPPC's response, is this:

- At NOPR P 33, FERC tentatively concludes that there are significant changes in the electric power industry since the planning processes under Order No. 890 took effect.

The Commission's assertion that there have been significant changes since the effective date of Order No. 890 is wholly unsupported. At NOPR n.41, without any direct reference to the alleged changes, the Commission cites only a 2010 study prepared by Edison Electric Institute ("EEI") which actually documents a trend toward increased transmission investment in the past several years. The Commission makes no effort to review changes to the landscape of the industry since implementation of Order No. 890. In fact, it has been just two and one-half years since the effective date of Order No. 890's Attachment K, a period sufficiently short that it is only now possible to begin to assess the effect of these new programs.

- At NOPR P 34, the Commission concludes that "siting, permitting and cost allocation of transmission facilities face significant challenges." In support, FERC cites a single comment offered by PJM in a news release indicating that an

---


additional line in the Eastern portion of its system would relieve congestion costs. On the strength of this observation, the Commission concludes at P 35 that "one deficiency that has arisen is the lack of a requirement for a regional plan, without which the construction of new facilities could be inhibited."

LPPC notes, at the outset, that a single anecdote regarding congestion costs on a portion of the PJM system is a terribly thin reed upon which to base a broad conclusion regarding the need to reform the planning process. It seems self-evident that the factors relevant to the completion of needed facilities within PJM are not related to other regions, particularly those that do not share planning processes remotely similar to PJM's. PJM's planning process is most unique. Of course, it already includes a regional transmission expansion plan ("RTEP"), which is the product of extensive regional-wide discussion and comment. What complexities beset the parties in that context, and why facilities the Commission believes should have been constructed were not undertaken, LPPC will not speculate upon. But it is worth emphasizing that the planning process in PJM has for some years been undertaken along with a program for broad cost socialization only recently upset by the Court in Illinois Commerce Commission v. FERC, 576 F.3d 470 (7th Cir. 2009) ("ICC v. FERC"). Quite possibly, parties opposed arguably needed facilities because they received little or no benefit from those facilities and therefore did not want to pay for them. Or, perhaps, as FERC points out, siting and permitting proved to be an obstacle. But if the latter was the case, there is nothing in the FPA or in the NOPR that would address those issues, since the Commission generally lacks siting authority.

At NOPR PP 36 – 37, FERC comments that "[a]nother deficiency that has arisen since the issuance of Order No. 890 involves transmission needs driven by public policy requirements established by state or federal laws or regulations," and adds that state RPS measures "accentuate the need for transmission. . ." The Commission concludes that "existing transmission planning processes were not designed to account for, and do not explicitly consider these types of public policy requirements established by state or federal laws or regulations." The Commission goes on to say that it "preliminarily finds that the failure to account explicitly for such public policy requirements in the transmission planning
process may result in undue discrimination and rates, terms and conditions of service that are not just and reasonable."

These concerns are baseless on a number of levels. First, it is worth observing that the state of play with respect to the number and ambition of state-based renewable energy portfolio requirements around the nation has not changed by orders of magnitude since the effective date of Order No. 890. Second, it is simply incorrect to assert that existing planning processes do not account for public policy requirements. As discussed at some length below, to the extent public policy requirements affect the demand for transmission service, there is absolutely no question that existing planning processes will take the policies into account. State-based Integrated Resource Planning ("IRP") protocols call for utilities to weigh a range of resource options and their public policy implications when considering how to meet demand. Further, pursuant to the Order No. 890-sanctioned study processes, the planning processes are required to study a certain number of hypothetical scenarios submitted by stakeholders that will, in all probability, reflect certain presumptions regarding policy requirements. Such studies will, as well, be undertaken on an interconnection-wide basis in the East through the Eastern Interconnection Planning Collaborative ("EIPC") and in the Western Interconnection through the Western Electricity Coordinating Council ("WECC").

---

12 In fact, since the effective date of Order No. 890, only four states (i.e., Kansas, Michigan, Missouri and Ohio) have enacted new RPS requirements, and a mere 4 additional states (Massachusetts, Maryland, Hawaii and Nevada) and the District of Columbia have increased their RPS targets. This is hardly representative of a need for widespread reform to promote transmission development. See State of the States: Update on RPS Policies and Progress Presentation, Lawrence Berkeley National Laboratory, at slides 6-8 (Nov. 2009), available at http://www.cleanenergystates.org/Meetings/RPS_Summit_09/WISER_RPS_Summit2009.pdf; see also Renewables Portfolio Standards in the United States: A Status Report with Data Through 2007, Lawrence Berkeley National Laboratory, at 3-4 (Apr. 2008), available at http://eetd.lbl.gov/ea/ems/reports/lbnl-154e.pdf.

Having said that, and as argued below, LPPC does not see the need for a broader requirement for system plans to reflect public policy in the abstract. As discussed below, LPPC is concerned that directing transmission planners to sift through arguably relevant laws and regulations, interpret those authorities, resolve conflicts and ascertain the impact these authorities will have on transmission demand will place unreasonable stress on the planning process, with inevitable conflict and delay as a consequence.

- At NOPR P 38, the Commission identifies as a "third deficiency…obstacles to non-incumbent transmission project developers' participation in regional transmission planning processes." Without recounting specific events, but citing certain parties' comments, the Commission concludes that the treatment of non-incumbent project developers in the transmission planning process constitutes undue discrimination.

LPPC welcomes the participation of non-incumbent transmission developers in regional and interregional planning processes. Indeed, these entities ought to (and generally do) participate in these processes. But LPPC disagrees strenuously with the Commission's view that non-incumbent transmission developers are within the class of entities to which the FPA protection against undue discrimination applies. The FPA protects customers from discrimination, not competitive transmission developers, as argued below. Furthermore, even if one assumed that the protection against discrimination is applicable, the differences between transmission development needed by load-serving entities to meet their service obligations and for-profit transmission developers amply justify differences in treatment, again as discussed below. Nor does the Commission compile any significant record of discrimination.

- At NOPR P 39, the Commission identifies as a fourth deficiency the lack of coordination between transmission planning regions. The Commission asserts that "...in the absence of such coordination between transmission planning regions, transmission providers may not identify more efficient and cost-effective solutions to the individual needs identified in their respective utility–level and regional planning processes, potentially including interregional transmission projects. The Commission concludes that "...the Order No. 890
transmission planning requirements may not be just and reasonable in that they
may not be sufficient to address the need for greater coordination in interregional
transmission planning."

Yet, the Commission's conclusions are bereft of any insight or analysis of the processes
only recently undertaken pursuant to Order No. 890, and certainly the more ambitious study
process now being undertaken through EIPC in the Eastern Interconnection and at WECC in the
Western Interconnection. These processes are only now underway, and the Commission's
tentative conclusion that they have not borne fruit is premature.

- At NOPR P 40, the Commission asserts that existing methods for allocating costs for
new transmission "may not be just and reasonable because they inhibit the
development of efficient, cost effective transmission facilities necessary to produce
just and reasonable rates."14 Citing the need for new intra-regional and interregional
facilities crossing transmission provider boundaries, the Commission says that there
are few rate structures in place that provide for the allocation and recovery of costs
for projects that are proposed to be located in more than one transmission planning
region, which "creates a significant risk for transmission project developers that they
will have no identified group of customers from which to recover the cost of their
investment."15

Rather than providing evidence, this passage simply assumes, without discussion, that
there is something wrong with establishing a rate structure which reflects traditional cost
causation theory, and the attendant incentives that project developers have to locate and size
facilities in order to meet demonstrated market demand. In fact, many interregional lines have
been built for decades by owners in different regions that recover their negotiated share of the
project costs from their transmission customers by filing to include the new project costs in their
respective transmission rate bases. LPPC believes this model is not broken and, as discussed
further below, is convinced that heavily subsidizing transmission development by socializing its
costs will not serve the public interest.

14 NOPR at P 39-41.
15 Id. P 41.
With this said, LPPC concludes there is effectively no evidentiary basis for the changes proposed in the NOPR. With no "evidence of a real problem" and little more than "theoretical potential for abuse," as was the case before the court in *National Fuel*, LPPC believes the Commission would be acting arbitrarily and capriciously to proceed on the scant evidentiary record compiled in the NOPR.

III. Proposed Reforms – Transmission Planning  (NOPR at PP 44 – 120)

   A. Participation in Regional Planning Processes  (NOPR at PP 44 – 54)

      1. LPPC Members Have Committed to Regional and Interregional Planning Processes.

The NOPR identifies alleged deficiencies in transmission planning and a perceived lack of coordination between regional transmission planning processes, adding that more efficient transmission solutions may be identified through regional planning than through independent evaluation by transmission providers.\(^\text{16}\) While LPPC agrees with the Commission that coordinated transmission study and development is important, the NOPR greatly underestimates the extent to which transmission projects are presently being studied and developed on a regional level throughout the nation.

In all regions of the nation in which LPPC members operate, processes are already in place or under development that address concerns highlighted in the NOPR and the Commission's interest in ensuring that needed regional and interregional transmission projects are studied and developed. To this end, LPPC members are committed to participating in regional and interregional planning processes, and are taking meaningful steps to improve interconnection-wide transmission planning in order to facilitate the development of

\(^{16}\) NOPR at P 39.
transmission facilities. Such coordinated efforts in each of the LPPC members' regions throughout the country are outlined herein, and discussed at length in the Attachment, below.\textsuperscript{17}

The southeast has adopted a bottom-up transmission planning process driven primarily by State-regulated resource planning processes that identify load growth and determine cost-effective, reliable solutions for meeting future demand. This process incorporates state and local "public policy" considerations, including the state-imposed "duty to serve" and results in a transmission plan that accounts for native load obligations and other firm transmission service commitments on a transmission system. Results from this process become inputs into utilities' Order No. 890 planning processes.

Regional transmission plans in the southeast are further reviewed by SERC Reliability Corporation ("SERC") and FRCC to facilitate simultaneous interregional feasibility and consistency in models and data and coordination occurs annually with other planning authorities in the Eastern Interconnection to produce interconnection-wide base cases that provide the foundation for transmission planning studies in the Eastern Interconnection.

Regional planning in the southeast is further integrated through the Southeast Inter-Regional Transmission Participation Process ("SIRPP"),\textsuperscript{18} which consolidates regional data and assumptions and develops planning models. SIRPP ensures consistency in data and facilities economic planning studies that involve impacts on multiple systems between regional planning processes. SIRPP also enables transmission owners to review regional data, assumptions and assessments being performed on an interregional basis.

---

\textsuperscript{17} This review focuses on non-RTO regions, and the accompanying coordinated interregional processes. Most LPPC members are located outside RTO and ISO boundaries. NYPA and LIPA are members of NYISO, while NPPD and Omaha Public Power District are members of SPP. Filings by those organizations will detail planning activities in those regions.

\textsuperscript{18} The SIRPP was established pursuant to a request from FERC Commission Staff during the initial Attachment K development process.
LPPC members of the Southwest Power Pool (“SPP”) Nebraska Public Power District (“NPPD”) and Omaha Public Power District (“OPPD”) are active participants in the planning process as described in Attachment O of SPP’s Tariff. A detailed description of SPP’s regional planning process is set forth in *Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010). NPPD, a member of the LPPC, recently joined SPP. *See Southwest Power Pool, Inc.*, 125 FERC ¶ 61,239 (2008).

Regional and interregional planning processes throughout the Eastern Interconnection are supplemented by the EIPC, which facilitates interconnection-wide planning and enables inputs from various stakeholders including state and federal policy makers and produces an interconnection-wide review of existing regional plans and transmission options associated with various policy options.

Transmission planning and expansion throughout the Western Interconnection is coordinated through the WECC and numerous regional and sub-regional planning groups (“SPGs”). LPPC members engage in joint regional transmission planning throughout the Western Interconnection through their participation in, among other regional and sub-regional planning groups, WestConnect and its Colorado Coordinated Planning Group (“CCPG”), ColumbiaGrid, the California Transmission Planning Group (“CTPG”) and, ultimately, WECC. The CCPG is a sub-regional process tasked with coordinating transmission planning information and sharing updated on active transmission projects. Transmission providers participating in CCPG submit their transmission plans for incorporation into CCPG transmission studies and plans, which are coordinated between neighboring sub-regional planning groups through the WestConnect transmission planning process. The WestConnect process enables coordination of study efforts between all SPGs within the WestConnect
planning area, and coordination with other Western Interconnection transmission providers and their SPGs through WECC's Transmission Expansion Policy Planning Committee ("TEPPC"), as discussed in the Attachment below.

LPPC members in the Pacific Northwest participate in ColumbiaGrid, which facilitates a "single-utility" approach to transmission planning. ColumbiaGrid coordinates with neighboring planning entities and SPGs through the WECC sub-regional and regional processes, and meets regularly with other SPGs to coordinate study activities, develop base case assumptions, and share planning information. LPPC members in California participate in the CTPG, which performs technical studies using California's Renewable Energy Transmission Initiative ("RETI") conceptual transmission plan to identify and coordinate transmission projects needed to meet state-wide renewable energy and RPS goals. The CTPG develops annually a California transmission plan that incorporates its participants' needs and identifies opportunities for joint transmission development.

WECC coordinates regional planning activities among SPGs, state and provincial agencies, balancing authorities and transmission providers in the Western Interconnection, and develops interconnection-wide databases for transmission planning analysis and reporting of all planned projects throughout the Western Interconnection.

WECC coordinates planned and proposed projects and identifies transmission needs and potential solutions through the TEPPC, which conducts Western Interconnection-wide economic studies in a transparent and open stakeholder process, and the Planning Coordination Committee's ("PCC") path rating process, which ensures that new projects will have no adverse impacts on existing facilities or approved projects. The TEPPC process is outlined in the Attachment, below. Importantly, TEPPC quantifies future transmission congestion and
examines the impact of transmission expansion scenarios, the results of which form inputs for regional and sub-regional processes. In this way, WECC supports a bottom-up/top-down approach to planning in the Western Interconnection that ensures that accurate, quality data and stakeholder-vetted assumptions and models are available for use in planning processes throughout the region.

WECC's transmission expansion planning processes are undergoing changes to better evaluate the reliability implications of state renewable energy policies. In this manner, interregional transmission planning throughout the West already incorporates policy-based needs and requirements into expansion plans, consistent with FERC objectives.

Regional processes are, of course, also under way in RTOs and ISOs throughout the nation, including those in which LPPC members participate, though LPPC expects that the Commission may be relatively more familiar with those processes than those in the non-RTO regions.

Comprehensive regional, sub-regional and interregional/interconnection-wide processes, then, already exist and promote stakeholder involvement and coordination. The NOPR fails to provide substantial evidence supporting the conclusion that these existing processes are flawed or insufficient to meet the Commission's stated goals. Worse, LPPC is deeply concerned that adoption of the NOPR's proposals would complicate regional and sub-regional planning efforts that are otherwise effectively coordinating, studying and implementing needed transmission solutions, and may very well undermine the Commission's stated goals.

2. **FERC Must Not Turn Regional Plans into Mandatory Templates.**

LPPC cautions the Commission against turning the proposed requirement that regional planning processes produce a regional transmission plan into mandatory FERC-approved
templates for planning and construction of facilities.\textsuperscript{19} LPPC believes that such a requirement would substantially inhibit the open and transparent planning processes already under way, and that it would exceed the Commission's jurisdiction.

LPPC notes, preliminarily, that the Commission's intention in this area is not altogether clear. At NOPR P 50, n.59, the Commission states that it does not propose "to dictate which investments identified in a transmission plan should be undertaken by transmission providers," as the Commission notes would be consistent with Order No. 890. Then again, while the NOPR does not say that the regional transmission plans it would direct must be filed with FERC, it does contemplate that the Commission will exercise oversight of the criteria pursuant to which facilities are included in regional plans,\textsuperscript{20} and that "each public utility transmission provider must revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a project in a regional transmission planning process." Such criteria "must not be unduly discriminatory or preferential."\textsuperscript{21}

When these provisions are taken together, it is difficult to know whether the Commission is contemplating a process pursuant to which it would direct transmission construction pursuant to FERC-approved transmission plans, perhaps upon complaint. If that is indeed the case, LPPC cautions the Commission that it would act on questionable jurisdictional grounds. LPPC notes, first, that transmission siting and construction are predominately state-based matters. Most transmission construction is undertaken for load-serving entities for the purpose of serving their native load. With the limited exception of those facilities designated in

\textsuperscript{19} See NOPR at P 50.
\textsuperscript{20} Id. P 70.
\textsuperscript{21} Id. P 90.
connection with congestion corridors under FPA section 216, 16 U.S.C. § 824(P), siting authority and construction oversight are exclusively state-based functions. See Piedmont Environmental Council v. FERC, 558 F. 3d 304 (4th Cir. 2009). Moreover, the overwhelming bulk of the nation's transmission investment outside of RTO regions is dedicated to bundled sales service, and the transmission revenue requirement for this investment is established in state-jurisdictional rates.

Transmission investment and planning is, accordingly, an area suffused with state-based concerns. FPA section 217 ("Native Load Service Obligation") reinforces this conclusion in two important respects. FPA section 217(e), 16 U.S.C. § 824q(e) ("Obligation to Build"), specifies:

Nothing in this chapter relieves a load-serving entity from any obligation under State or local law to build transmission or distribution facilities adequate to meet the service obligations of the load-serving entity.

Further, FPA section 217(b)(4), 16 U.S.C. § 824q(b)(4), specifies:

The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities…

In addition, it bears pointing out that FPA section 202(a), 16 U.S.C. § 824a(a), stipulates that "…the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission and sale of electric energy…"22

Together, these provisions make it clear that FERC has no authority to direct utilities to carry out specific transmission plans, to undertake construction according to those plans, or to

22 16 U.S.C. § 824a(a) (emphasis added).
transfer responsibility for projects in their construction plans to non-incumbent transmission developers, as may be contemplated in the proposed rule. Instead, the FPA plainly contemplates that such plans are largely a state concern, and that such coordination as FERC may engender will be accomplished on a voluntary basis, and in a manner that facilitates the ability of load-serving entities to meet their service obligations. Again, LPPC emphasizes that its members are committed to the open and transparent regional planning protocols promulgated under Order No. 890. Further, LPPC members are participating in interregional planning processes, and commit to enhancing and building on those programs, as discussed below. But having said that, LPPC does not think the Commission can or should take the further step of assuming it has the authority to direct utilities to undertake specific siting and construction programs.

B. Public Policy Driven Projects (NOPR at PP 55 – 70)

1. It is Unreasonable to Mandate that Public Policy be Taken into Account in Transmission Plans Other Than to the Extent it Translates into Actual or Anticipated Transmission Demand.

FERC proposes to require public utility transmission providers to amend their OATTs in order to provide that local and regional transmission planning processes will consider public policy requirements established by state or federal laws or regulations that may drive transmission needs.\(^{23}\) Rather than specifying the public policy requirements established by relevant state and federal laws or regulations, the Commission proposes to require each public utility transmission provider to coordinate with customers and stakeholders in order to identify relevant state and federal laws and regulations.\(^{24}\)

\(^{23}\) NOPR at P 64.

\(^{24}\) Id. P 65.
The proposed requirement would be unnecessary, potentially confusing and ultimately counterproductive. There is no doubt that state and federal law and regulations may very well have an ultimate impact on system planning. But, LPPC notes, first, that there are a wealth of federal and state laws and regulations bearing on system planning. By leaving open for further discussion how system planners and interested parties will sift through these requirements in developing priorities and ensuing planning decisions, LPPC is most concerned that the proposed directive would engender nearly endless debate and controversy.

Even among those state laws that will have an obvious effect on demand, such as state-based RPS requirements, actual impacts will call for the exercise of subjective judgments. There are many ways to respond to an RPS, and responses will vary by utility and by state. The options include reliance on local renewable resources, recourse to demand response and efficiency initiatives (reducing demand for transmission), and the use of remote renewable generation (increasing demand for transmission). Customarily, all such options are identified and evaluated by resource planners, following which the load-serving entity selects "winners." Those decisions then dictate site-specific points of injection and withdrawal on the grid, enabling transmission planners to draw appropriate conclusions regarding the need for transmission upgrades.\(^{25}\)

The bottom line is that it would not be cost effective, nor would it further environmental goals, for the Commission to direct transmission planners to select multi-billion dollar interregional transmission projects before load-serving entities make their determinations regarding needed resources. Ultimately, all that matters in connection with the formulation of a

\(^{25}\) This statement is not intended to imply that transmission upgrade costs are disregarded by resource planners. Resource planners normally include an estimate of the transmission costs associated with each option they evaluate.
transmission plan is the projected demand for transmission service. Asking transmission planners to divine when and where their customers will need transmission upgrades based on their analysis of public policy is a prescription for confusion, potential stranded costs, and litigation that may set back existing planning processes for years.

2. FERC Does Not Have Jurisdiction to Consider Broad Notions of Public Policy under the Federal Power Act.

LPPC cautions the Commission that outside ascertaining the impact that public policy may have on transmission demand, an effort directly to advance such policies is beyond the Commission's jurisdiction. It is well settled that FERC's statutory mission under the FPA is to ensure reliable service at just and reasonable rates. *See National Assoc. for the Advancement of Colored People, et al. v. FPC*, 425 U.S. 662, 669-70 (1976) ("NAACP") ("the principle purpose of [the FPA] was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices."). As the Supreme Court concluded in *NAACP*, Congress' direction to the Commission to act in furtherance of the "public interest" under the FPA "is not a broad license to promote the general public welfare." *Id.*, 425 U.S. at 669-70. Accordingly, it is clear that FERC lacks the authority to advance "public policy," broadly construed. Rather, the Commission's mission under the FPA is confined to ensuring that reliable electric service is provided at just and reasonable rates.  

It is also worth pointing out that the Commission has on several occasions itself recognized this limitation in connection with its authority to consider environmental policy objectives under National Environmental Policy Act ("NEPA"). *See Monongahela Power*, 39 FERC at 62,097. While FERC's NEPA-related responsibilities extend to oversight of

hydroelectric projects and natural gas pipeline facilities, they "do not extend to electric rate filings pursuant to [FPA] section 205."\(^{27}\) In fact, the Commission's regulations implementing NEPA provide, in relevant part, that "neither an environmental assessment nor an environmental impact statement will be prepared for [projects or actions including] [e]lectric rate filings submitted by public utilities under [FPA] sections 205 and 206 [and] the establishment of just and reasonable rates."\(^{28}\)

LPPC also sees the potential for considerable mischief in asking transmission planners to seek their own counsel in ascertaining the public policies to which they must respond. In fact, the discretion that this approach would interject into the planning process would seem to be an open door to potential discrimination, and a nightmare to enforce, as parties debate whether planning adequately responds to a variety of potentially competing policies.

C. Opportunities for Undue Discrimination against Non-Incumbent Transmission Developers. (NOPR at PP 71 – 101)


LPPC does not generally object to FERC's proposed tariff revisions specifying the terms under which non-incumbent transmission developers will participate in the planning process.\(^{29}\)

The effort to specify procedures for ensuring that non-incumbent transmission developer

\(^{27}\) Id. (noting that to implement NEPA, the FPC, FERC's predecessor agency, issued policy statements requiring the preparation of environmental impact statements in connection with the construction of facilities subject to its licensing jurisdiction). The Commission has on several occasions recognized that its review of electric rate filings is not subject to NEPA and, therefore, did not order environmental impact statements to be prepared. See Southern Co. Services, Inc., 22 FERC ¶ 61,047 (1983); Southern Co. Services, Inc., 12 FERC ¶ 61,081 (1980); In the Matter of NEPOOL Power Pool Agreement, 48 FPC 1477 (1972).


\(^{29}\) NOPR at PP 90-96.
proposals may be evaluated, and the developers' fitness to complete projects determined, is generally sensible.

LPPC does object to the Commission's tentative determination\(^30\) not to require a transmission developer to participate in the regional transmission planning process if it does not seek to use the regional cost allocation process. The Commission reasons that in such cases, the fact that beneficiaries need not be identified for cost allocation purposes appropriately relieves the project developer of an obligation to participate in regional planning.\(^31\) This reasoning is unsound. The presence of substantial new facilities interconnected with the electrical grid must be taken into account and studied in regional and interregional processes. Regardless of the provisions governing cost recovery for such facilities, they will have impact on grid capabilities and operations that cannot be ignored. There is no basis for permitting the developers of such projects to exempt themselves from regional fora.

2. **FERC Orders or Rules Compelling Utilities to Defer to Non-Incumbent Transmission Developers in the Construction of Facilities Needed to Serve Native Load Would be Beyond its Jurisdiction.**

Where utilities identify facilities that are needed to serve their native load, they must be permitted to undertake construction in order to meet their service obligation. Although LPPC is not certain of FERC's intention in this area outside the RTO/ISO setting, LPPC emphasizes that a utility's ability to construct facilities it needs to meet its service obligation cannot be impeded.

Outside the RTO/ISO setting (where FERC clearly has proposed to eliminate any rights of first refusal to construct transmission facilities that may be granted to incumbent utilities), FERC's intention with respect to incumbent utility rights is unclear. At NOPR P 87, the

\(^30\) *Id.* P 99.

\(^31\) *Id.*
Commission tentatively concludes that "there appear to be opportunities for undue discrimination and preferential treatment against non-incumbent transmission developers with existing regional transmission planning processes." The Commission goes on to assert that "…it may be unduly discriminatory or preferential to deny a non-incumbent transmission developer that sponsors a project as part of a regional transmission plan the rights of an incumbent transmission provider."\textsuperscript{32} At NOPR P 97, the Commission states:

\begin{quote}
We emphasize that these proposed reforms would apply only to facilities that are evaluated in a regional transmission planning process and selected for inclusion in a regional transmission plan. We do not propose to modify any existing obligation for an incumbent transmission provider to build unsponsored projects that are identified as necessary in the regional transmission plan… (emphasis added)
\end{quote}

Read in isolation, that passage suggests that where non-incumbent transmission developers sponsor new projects (even if they are identified by an incumbent utility as essential in performing their service obligation), they may be given a federal priority to build facilities. Conceivably, the Commission intends these priorities to be enforceable to the extent commitments are made pursuant to the interregional planning agreements that the Commission proposes must be filed with the Commission and subject to protocols for evaluating sponsored projects.\textsuperscript{33} Nonetheless, FERC goes on to state:

\begin{quote}
We also emphasize that these proposed reforms would only affect a right of first refusal established in a transmission provider's OATT or agreements subject to the Commission's jurisdiction. This Proposed Rule does not address, propose to change, or seek to preempt any state laws or regulations.\textsuperscript{34}
\end{quote}

Accordingly, LPPC is genuinely uncertain whether it is FERC's intention to leave unaffected the construction plans a utility may have to meet its native load service obligation, or if FERC

\textsuperscript{32} Id. P 87.
\textsuperscript{33} See id. P 118.
\textsuperscript{34} Id. P 98.
intends that non-incumbent transmission developers be given the opportunity to compete to construct such facilities, perhaps on the ground that their facilities serve markets more efficiently.

LPPC would very much like to think that the Commission's intention is to leave intact incumbent utilities' authority to do what they must to carry out their obligation to serve native load, by their own lights and subject to state regulatory oversight. And it certainly seems possible that the role for non-incumbent transmission developers that the Commission envisions involves projects that are either unrelated to LSE service obligations, or in which traditional utilities choose to work with non-incumbent developers. But, if the Commission's aim is otherwise, LPPC objects on the ground that the Commission lacks statutory authority to act in this manner.35

FERC's reliance on the FPA's prohibition of undue discrimination to promote the rights of non-incumbent transmission developers lacks any statutory basis. FPA section 205(b) proscribes both "any unreasonable differences in rates" and any "undue preference or advantage."36 Yet, it is well settled that "]t]he purpose behind [FPA] section 205(b) is the protection of the consumer's interest" (emphasis added).37 Contrary to the NOPR's apparent assumption, the intent of the statute's undue discrimination protections "is to protect consumers [ ] from being placed at a competitive disadvantage with other [similar customers]."38 There are

35 LPPC does not object to the location of non-incumbent facilities within the footprint of existing utility systems, nor does it think that a right of first refusal must be maintained by incumbent utilities for all such facilities. LPPC's concern is rather to ensure that utilities have the unfettered right to build facilities that are needed in order to serve their load.

36 16 U.S.C. 824d(b); see also Alabama Elec. Co-op., Inc. v. FERC, 684 F.2d 20, 28 (D.C. Cir 1982).

37 Pub. Service Co. of Ind., Inc. v. FERC, 575 F.2d 1204, 1213 (7th Cir. 1978) ("Indiana"); see St. Michaels Util. Comm'n v. FPC, 377 F.2d 912, 915 (4th Cir. 1967) ("St. Michaels").

38 Indiana, 575 F.2d at 1212 (emphasis added); see City of Frankfort, Ind. v. FERC, 678 F.2d 699, 707 (7th Cir.
essentially two (and only two) types of undue discrimination: treating similar customers differently or according similar treatment to dissimilar customers. Alabama Electric Cooperative v. FERC, 684 F.2d 20, 27-28 (D. C. Cir. 1984). But in each case the discrimination is between a public utility’s customers or classes of customers (including the public utility’s treatment of itself as a customer). Thus, while section 205(b) plainly protects competitors of jurisdictional service providers in their capacity as customers (including protection against anticompetitive discriminatory conduct), the FPA's undue discrimination protections simply do not extend to non-incumbent transmission providers as competitors.

To the same effect, in City of Frankfort, addressing a municipal customer's undue discrimination claim against a public utility, the court noted that FPA section 205 provisions "regarding unlawful preference or advantage in setting of public utility rates requires that utility customers be treated fairly (emphasis added)." City of Frankfort, 678 F.2d at 704. Similarly, the court in Indiana stated that "the anti-discrimination policy in [FPA] section 205(b) is violated [ ] where one consumer has its rates raised significantly above what other similarly-situated consumers are paying." The Indiana court went on to note that, "[i]n such a case, the lone customer" has recourse to the Commission under FPA section 205(b) when it is put in "an unjustifiably non-competitive position." Indiana, 575 F.2d at 1213. According to the Indiana court, the Commission, in evaluating utility requests to increase rates to customers, "should not ignore its responsibility to the consumer under [FPA section] 205(b)." Id. The rights of

competitors, then, are neither protected nor contemplated in FERC's FPA section 205(b) proscription against undue discrimination.\[39\]

Underscoring the illogic of the proposed expansion of the anti-discriminatory provision in the FPA to transmission developers in their role as competitors of existing transmission providers is the fact that the Commission plainly lacks general jurisdiction over the siting, construction or ownership of transmission facilities, matters that Congress intentionally left to the states, as demonstrated by a comparison between the FPA and the Natural Gas Act ("NGA"). FPA section 201(a), 16 U.S.C. § 824(a), provides for FERC jurisdiction over "the business of transmitting and selling electric energy" at wholesale with "such Federal regulation [ ] to extend only to those matters which are not subject to regulation by the States." In contrast, NGA section 7, 15 U.S.C. § 717f, expressly grants to FERC siting and construction authority over natural gas pipelines.

Even assuming, arguendo, that non-incumbent transmission providers – in their role as transmission providers rather than customers – fall under the ambit of the FPA's undue discrimination protections, these transmission providers are not similarly situated to incumbent utilities. FERC's authority under the FPA to remedy unlawful preference or advantage in public utility rates is grounded in protecting consumers from being placed at a competitive disadvantage with respect to other similar customers. See City of Frankfort, 678 F.2d 699. Indeed, the FPA does not prohibit all discrimination, only undue discrimination, and FERC has

\[39\] The Commission has itself commented that its job is to protect competition, not competitors. See Entergy Services Inc., 64 FERC 61,001 at 61,013, n.66 (1993) (citing Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc., 429 U.S. 477, 487-89 (1977); Cargill, Inc. v. Montfort of Colorado, Inc., 479 US 104, 115-17 (1976)). To the extent the Commission has conceptualized its open access policy to be in furtherance of antitrust principles, it is further worth noting that the Supreme Court has made clear that the antitrust laws "were enacted for the protection of competition, not competitors." Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc., 429 U.S. 477, 487-89 (1977) (quoting Brown Shoe Co. v. US, 370 U.S. 294, 320 (1962)).
generally found that discrimination is "undue" when there is a difference in rates, terms or conditions among similarly situated customers.\textsuperscript{40} There is nothing unduly discriminatory about treating differently situated entities differently.\textsuperscript{41} Unlike non-incumbent transmission developers, by virtue of their state-based franchises, incumbent utilities are legally bound by a "duty to serve," an obligation that carries with it a commitment to construct and maintain facilities necessary to render reliable, cost-effective service to customers in their service territories. Non-incumbent transmission providers are self-evidently not bound by a similar obligation.

FPA Section 217(e), 16 U.S.C. § 824q(e), expressly recognizes the primacy of a franchised utility's obligation to do what is needed in order to fulfill its obligation to serve, specifying that "[n]othing in this chapter relieves a load-serving entity from any obligation under State or local law to build transmission or distribution facilities adequate to meet the service obligations of the load-serving entity." The flip side of that coin is the plain implication that the Commission must do nothing to impede load-serving entities' ability to meet their service obligations, and to take primary responsibility for the construction of the facilities necessary to do so.

LPPC adds that if, indeed, it is the Commission's intention to require utilities to defer to non-incumbent utilities in connection the construction of facilities that are required, even in part, for reliability purposes, meaningfully more thought must be given to the practical issues


\textsuperscript{41} See, e.g., Sebring Util. Comm'n v. FERC, 591 F.2d 1003, 1009 n.24 (5th Cir. 1979) (the "essence of the principle" of the prohibition against undue discrimination "is that those who are similarly entitled must be treated equally"); Transwestern Pipeline Co., 38 FERC ¶ 61,175, at 61,433 (1986) ("Undue discrimination is in essence an unjustified difference in treatment of similarly situated customers.").
presented by that approach. It is not clear to LPPC, among other things, whether utilities' service obligations that depend on the completion of non-incumbent facilities may be mitigated if the facilities are unavailable.

D. **Interregional Coordination (NOPR at PP 102 – 120)**

1. **LPPC Members Will Participate in Consensus-Based Interregional Planning Processes.**

LPPC members stand ready to participate in interregional planning processes reflecting the basic precepts articulated by the Commission in the NOPR at P 117-118, viz.,

- Coordination and sharing results of respective regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities;

- the exchange at least annually of planning data and information;

- a process for identifying and jointly evaluating transmission facilities that are proposed to be located in both regions; and

- a commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process

As described in the Attachment, LPPC members are already actively engaged in regional and interregional planning.

2. **LPPC Members Cannot Commit to Entering FERC-Jurisdictional Agreements Containing Interregional Planning Protocols.**

While LPPC members will commit to participate in interregional processes consistent with Commission's articulated principles, they cannot commit to enter into the interregional planning agreements that the Commission contemplates will be filed with it. For one thing, apart from the general topics the Commission has listed for consideration in these agreements, it is not possible at this time for LPPC members to ascertain what commitments may be called for in such agreements. Among the many matters that remain undetermined are whether these
agreements: (1) will carry with them specified or open-ended liability; (2) may include an obligation to defer to regional or interregional transmission plans that would, in the members' judgment, interfere with what must be done to honor an obligation to serve; (3) may impose construction obligations or other unanticipated costs on the members; and (4) will be subject to FERC modification in ways that will affect members' responsibilities and liabilities.

The authority pursuant to which LPPC members enter into binding contractual commitments is quite varied. Because LPPC members are creatures of state and municipal governments, and are created by statute or municipal ordinance, their authority to enter into binding arrangements is in all cases tightly circumscribed in a manner that is consistent with their fiduciary responsibilities and will protect state and municipal sovereignty. Members are also restricted in their contracting practices by covenants in their financing arrangements, and cannot volunteer to enter into agreements that would, among other things, violate or jeopardize a private activity bond rule for purposes of section 141 of the Internal Revenue Code of 1986, 26 U.S.C. § 141, or any successor statute or regulation. With all of this in mind, LPPC members cannot commit to enter agreements at this time, and cannot do so until substantial additional definition and assurance is provided.

IV. Proposed Reform - Cost Allocation (NOPR at PP 121 – 178)

A. Introduction

At NOPR P 156, the Commission indicates that it proposes "to more closely align transmission planning and cost allocation processes." LPPC can support this approach, to the extent that what is contemplated is the creation of a regional forum enabling parties to consider mechanisms for recovering the costs of planned new transmission facilities in a regional setting.

In addition, LPPC supports certain of the guideposts established by the Commission for these discussions. LPPC agrees with the Commission that the approach to cost recovery must
reflect regional characteristics, and that a national template is not advisable. Some of the
fundamental differences between regions bearing on transmission plans and cost recovery
include dramatically different generation resource bases, the state of existing infrastructure
development and different market structures. Accordingly, LPPC supports the Commission's
decision\(^{42}\) not to proceed with a uniform template for the treatment of cost across regions.

As well, LPPC agrees with the Commission that "those that receive no benefit from
transmission facilities, either at present or in any likely future scenario, must not be
involuntarily allocated the costs of those facilities."\(^{43}\) While that proposition might seem self-
supporting, LPPC understands that there are those who would encourage the Commission to
mandate socialization of cost on a regional or even interconnection-wide basis. FERC's
decision to step back from the brink on that issue is sensible. On a related note, LPPC supports
the Commission's tentative conclusion\(^ {44}\) that costs for intraregional facilities should not be
allocated to entities outside the region absent voluntary agreement.

LPPC cannot agree, however, with the Commission's tentative conclusion that a regional
plan which relies exclusively on a “requestor pays” approach will in all cases be unacceptable.\(^ {45}\)
The Commission itself notes that it only recently accepted quite a number of Order No. 890
compliance filings from utilities outside RTO and ISO footprints in response to Order No. 890

\(^{42}\) NOPR at P 165.

\(^{43}\) Id. P 164, item 2.

\(^{44}\) Id., item 4.

\(^{45}\) Id. P 168. The NOPR refers to this approach as “participant funding,” although that terminology is drawn from
cases in which the costs at issue were incurred by transmission providers providing service to their customers on a
single system. As used in the NOPR, the term refers to the recovery of costs by entities spanning two or more
transmission provider systems from entities requesting service on the new facilities. Since the term “participant
funding” is used by the NOPR out of context, LPPC instead refers to an approach for recovery from customers
taking service over a transmission developer’s lines spanning two or more transmission provider systems as a
“requestor pays” approach.
that rely exclusively the allocation of transmission costs to entities which agree to pay them. A Commission order directing that this approach be changed can only follow lawfully from a finding that rates in regions which employ a participant funding approach are unjust and unreasonable, or that they are unduly discriminatory. Yet, as discussed below, the Commission fails to establish a record demonstrating the need for generic rate reform, and there is substantial evidence of robust transmission development without it.

From a policy standpoint, LPPC sees in proposals for broad cost socialization of regional and interregional transmission projects the perversion of cost signals that are essential in ensuring that resources are appropriately used and conserved, and that cost to consumers are minimized. Moreover, by marrying transmission planning to cost socialization, LPPC envisions endless controversy, as facilities that may otherwise have been supported by voluntary agreement are endlessly debated and litigated by parties hoping to shift costs to others.

As a matter of law, LPPC sees no basis for the Commission to permit transmission developers to assess costs to entities other than their customers. The FPA grounds the Commission's authority on a service relationship between a utility and its customers. Absent the provision of service to a customer under a tariff or contract, there is no authority to assess costs.

Further, LPPC is concerned that in evaluating the quantum of proof needed to impose costs on entities based on an assessment of ostensible "benefits," the Commission is prepared to act on the strength of less-than-rigorous evidence. Judicial precedent and the Commission's own ratemaking tradition call for the Commission to honor "cost causation" as the fundamental

\[46\] As discussed above, the Commission lacks a statutory basis for protecting non-incumbent transmission developers from discrimination, leaving its authority to ensure that rates are not unjust and unreasonable as the remaining basis for action in this area.
touchstone for rational cost allocation. Yet, LPPC is concerned that the Commission may be giving no more than perfunctory consideration to this concept.

B. The Commission Demonstrates No Basis for Generic Rate Reform and there is Substantial Evidence of Robust Transmission Development Without it.

The Commission has the authority to change rates under the FPA only upon a finding that existing rates are unjust and unreasonable. Yet, the ostensible findings the Commission makes in support of generic rate reform – and its view that participant funding for region-wide transmission projects is impermissible – are thin, and certainly not applicable nation-wide. The Commission makes only two assertions of fact in articulating "The Need For Reform" at NOPR PP 148 – 154. These are that:

- "...further expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions." and

- "...the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of location-constrained renewable energy resources that are frequently remote from load centers, as well as a growing need for new transmission facilities across several utility and/or RTO or ISO regions."

Apart from these conclusory statements, the NOPR is bereft of any record evidence demonstrating unfulfilled transmission needs that can only be addressed through the rate reforms the Commission suggests. Perhaps regional power markets have experienced some expansion in recent years, and perhaps this has created some incremental demand for cross-regional wholesale transmission service. But the Commission offers no evidence of these

47 See Atlantic City Elec. Co. v. FERC, 295 F.3d 1 at 10 (D.C. Cir. 2002) ("The courts have repeatedly held that FERC has no power to force public utilities to file particular rates unless it first finds that existing filed rates unlawful.")
48 NOPR at P 150.
49 Id. P 151.
phenomena, and LPPC members are unaware of any groundswell of complaints in the regions in which they serve from load serving entities or state officials claiming that the transmission system is inadequate to reliably serve native load. Equally important, the Commission offers no evidence that reforms of the type it entertains in the NOPR, including the elimination of participant funding for cross-regional facilities, are a necessary or satisfactory solution to the perceived problem. As the court reminded the Commission in National Fuel, "[p]rofessing that an order ameliorates a real industry problem, but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making."50

As to the Commission's assertion that the increasing adoption of resource policies and RPS requirements is driving increasing interest in location constrained renewable resources, it is worth observing, first, that state-based RPS requirements are not ubiquitous.51 In the Southeast, e.g., only North Carolina has an RPS requirement (i.e., 12.5% by 2021),52 and there is no suggestion in any quarter that a regional mechanism for funding transmission is needed in order to satisfy that requirement. Moreover, nation-wide, there is no indication that RPS requirements have increased meaningfully in the period since the issuance of Order No. 890.53

Turning to what we do know, there is very good reason to conclude that transmission investment has increased substantially in recent years, while the anticipated trend continues to be upward. Moreover, regional and interregional transmission project development continues


52 Id.

53 See supra, p. 8-9, n.11.
for projects that enjoy market support without the inefficiencies that come with cost socialization. Estimated future transmission expenditures illustrate that this is a lasting trend.

In its recent report on nation-wide transmission infrastructure investment, EEI indicates that "[d]espite the economic downturn, the investment being made by EEI member companies is significant and growing, and reflects preparation for future customer needs." According to EEI, from 2001 to 2008 its members, who represent approximately 70 percent of the electric power industry in the country, invested nearly $57.5 billion in transmission infrastructure improvements. EEI adds that while its Report is not a comprehensive compilation of all projects being pursued by its membership, the representative projects in the Report total nearly $56 billion (nominal dollars) in expected future transmission system investments from 2009 through 2020 (see Figure 1). According to EEI, this is only a portion of the total transmission investment anticipated through 2020 by EEI member companies. EEI's members invested $9.1 billion in 2008, with planned additional investments of $33.9 billion in the transmission system between 2009 and 2011.

54 See EEI Report at iii. EEI's Report focuses on projects that were completed in 2009 or are expected to be completed by 2020, representing a one year back looking and 10 year forward looking window. Id., vii. EEI's members represent approximately 70 percent of the electric power industry in the U.S. Id.

55 Id. The $57.5 billion figure is in 2008 dollars.

56 Id.

57 Id., vii.
Further, of particular significance in this docket, the vast majority (i.e., 70 percent) of transmission investment and development is interstate (see Figure 2). According to EEI, the large interstate projects included in its Report span multiple states and account for approximately 10,000 circuit miles of transmission representing $39 billion (nominal dollars) of investment.\textsuperscript{59}

\textsuperscript{58} Id.
\textsuperscript{59} Id., viii.
Similarly, most \textit{i.e.,} 66 percent of the representative projects in EEI's Report are or have been developed to facilitate the integration of renewable resources, with an accompanying transmission investment cost of approximately $37 billion (nominal dollars). EEI references several specific projects falling into this category of transmission development, including the Northeast Energy Link ("NEL"), Green Power Express, and the Canada-Pacific Northwest-California Transmission Project ("CNC Project"), all of which are regional or interregional in nature. The NEL is a proposed 240-mile, 1,100-MW high-voltage DC transmission line stretching from Northern Maine to Northeast Massachusetts, and will deliver cost effective renewable and low-carbon resources located in northern New England and the Canadian Maritimes into the Northeast Massachusetts load zone. Green Power Express is a vast 765-kV transmission overlay project spanning numerous states and several regions from the Midwest through the Great Plains. With an estimated cost of between $10-12 billion, Green Power

\begin{figure}
\centering
\includegraphics[width=0.5\textwidth]{representative_project_interstate_vs_non_interstate_transmission_investment}
\caption{Interstate vs. Non-Interstate Transmission Investment\textsuperscript{60}}
\end{figure}

\begin{itemize}
\item \textsuperscript{60} \textit{Id.}, ix.
\item \textsuperscript{61} \textit{Id.}
\item \textsuperscript{62} \textit{Id.}, 35.
\end{itemize}
Express consists of nearly 3,000 miles of transmission line to transport primarily wind resources to Midwest load centers and further east. The CNC Project will transport up to 3,000 MW of power from renewable resources in British Columbia, Canada to the Pacific Northwest and northern California, over a 1,000 miles long transmission line. As EEI indicates, the CNC Project "will enable and advance inter-regional and international development and integration of renewable energy resources, as well as provide a platform for integration and coordination of a number of regional transmission projects now being considered in the Pacific Northwest."64

In addition to the projects recognized in the EEI Report, other regional and interregional merchant transmission projects have emerged. Pattern Energy Group, for instance, has recently unveiled an expansive $1 billion Southern Cross Project transmission proposal that would carry up to 3,000 MW of renewable power from Texas to the Southeast. The Southern Cross Project proposes an HVDC line connecting the AC lines developed as part of Texas' "competitive renewable energy zone" effort with AC lines in Mississippi owned by the Tennessee Valley Authority, Southern Company and/or Entergy over separate 500 kV lines.65

Each of these projects is representative of the considerable transmission development efforts being accomplished nationwide, and further illustrates the investment being made in regional and interregional transmission projects and, in particular, projects designed to integrate renewable resources. These projects are being developed or planned under existing regulatory

63 Id., 25.
64 Id., 64.
structures and without the need for additional incentives. FERC itself acknowledged this in its NOPR and recognized that "a trend of increased investment in the country's transmission infrastructure has emerged in recent years." Yet at the same time the NOPR severely underestimates the extensive investment in transmission projects in the aggregate and into the future, and substantially overlooks regional and interregional projects that are being advanced without the socialization of costs.

LPPC members report that the experience of EEI's members is typical of what has occurred industry-wide. As will be reported in comments filed by LPPC members in the West, transmission developments in which LPPC members are participating are proceeding apace, while LPPC members in the Southeast are pleased to note that the region has been given a stellar report card by the Department of Energy ("DOE") for recent transmission development. In December of 2009, DOE concluded that there is little economic or reliability congestion in the Southeastern United States "[b]ecause the Southeastern utilities build aggressively in advance of load." And this system should remain robust, as SERC members have invested approximately $1.9 billion in new transmission lines and system upgrades 100 kV and above in 2009 and plan to spend approximately $2.4 billion in 2010 and approximately $2.3 billion in 2011.

66 NOPR at P 33, n.41.
C. **Cost Subsidization for Long-Line Transmission Development Tilts the Balance in Determining how to Meet Renewable and Carbon Control Goals, and will Engender Needless Controversy, Ultimately Impeding Project Development.**

The call for regions, and perhaps for multiple regions, to spread the cost of new transmission facilities to all load effectively asks that resources requiring long-line transmission facilities be provided an enormous subsidy. As load-serving entities search for resources to meet load requirements and various policy initiatives (including state or federal RPS, or carbon control requirements), such subsidization will foreclose reliance on otherwise economic alternatives, needlessly increasing costs to consumers, while risking substantial stranded costs in the event remotely-located resources prove to be uneconomical despite their subsidization. Further, cost subsidies undermine the discipline present when a project developer must ensure that there is market support for its project. Market discipline is critical in ensuring that investments are undertaken efficiently, balancing the nominal cost of the project and alternatives, against location and the associated transmission cost. Transmission subsidies skew that decision-making.

Building transmission to access remotely located renewable resources is only one of many means by which utilities may respond to requirements to reduce greenhouse gases ("GHGs"). Studies by the Electric Power Research Institute ("EPRI") (the "Full Portfolio" analysis) and by McKinsey and Company in its 2007 "U.S. Greenhouse Abatement Mapping Initiative" show a wide variety of options that may be employed in meeting GHG reduction, including: energy efficiency initiatives (many calling for capital investment); conversion of existing generation to more efficient operations; the development of additional nuclear capability; advanced coal generation and carbon capture and storage; distributed renewable
resources (including distributed solar); plug-in hybrid vehicles and the development of large-scale remotely located renewable generation.  

State-based RPS requirements, and potentially a federal RES or carbon control regime, will provide utilities with a powerful incentive to employ all available options for GHG emission reductions. Of course, many utilities will make plans to build new transmission facilities in order to access remotely located renewable resources, while project developers will have reason to invest in such facilities in order to access newly motivated markets. But socializing the cost of that transmission will tilt the playing field dramatically away from any alternatives that do not depend heavily, or at all, on transmission. If the substantial cost of transmission to remote resources is forced upon all load, it will be, to use an economist's term, sunk cost, and alternatives to meeting carbon control requirements will be far less economical by comparison. This will have the effect of crowding out more cost-effective investment in other means of satisfying environmental goals, including the reliance on local renewable resources. LPPC notes, e.g., that JEA, an LPPC member, has made a significant commitment to solar energy, agreeing to purchase the full output of a 12.7 MW central station solar photovoltaic plant under construction in Jacksonville, Florida from 2010 through 2040. Heavy transmission subsidies for other forms of remote renewable energy may very well have undermined this project, and the nascent solar industry in the Southeastern U.S.

LPPC adds that it seems quite probable that the mandatory socialization of transmission costs may very well have the unintended effect of inhibiting transmission development. That is why it is critical for the Commission to adhere to the cost causation principles articulated in ICC

---

v. FERC. It is evident that transmission development has picked up in the past few years, as the Commission itself notes.\textsuperscript{70} To the extent this transmission is planned to span utilities and/or RTOs, current plans call for it to be paid for by entities planning to use the facilities or otherwise handled through existing rate structures.\textsuperscript{71} Logically, if the Commission eschewed cost causation principles, project developers and potential customers would hold out for subsidized treatment. Complicating matters further, there is every reason to believe that with the potential for cost socialization, the planning process will become vastly more contentious, slowing down needed projects, as parties who do not see themselves benefiting from facilities, but nonetheless fear bearing the related costs, seek to thwart the projects, even as other entities seek to ensure that costs they might otherwise agree to incur themselves are offset by regional contributions.

The Commission’s affirmance of the cost causation principle notwithstanding, the Commission appears to suggest that, to prevent what it refers to as “free ridership,” costs can nonetheless be allocated to parties based on the theoretical benefits they receive – even absent a customer/provider relationship.\textsuperscript{72} This is a solution in search of a problem. LPPC cannot agree with the Commission that cost socialization is needed, much less permitted, in order to protect against the inequities of perceived “free ridership,”\textsuperscript{73} a concept that the Commission takes to refer to the relatively cost-free transmission that may be provided to entities who take advantage of others' oversized investments. It is self-evident that this concern comes with an existing set

\textsuperscript{70} NOPR at P 33, n.41.


\textsuperscript{72} NOPR at P 142, 168.

\textsuperscript{73} Id. P 142, 168.
of ready solutions, including a Commission determination that such late-comers will bear a portion of the initial investors' capital costs. Alternatively, the creation of a robust secondary market permitting the recovery of capital costs will address this issue.

Finally, LPPC points out that the NOPR's proposal is completely at odds with the manner in which the Commission approaches new interstate gas pipeline developments. In fact, all such projects are self-sustaining, and do not derive any subsidization from existing services. As is economically appropriate, such projects are sustainable and supported by sufficient demand to justify the project developers' costs. This approach is also consistent with the Commission's current approach to independent electric merchant transmission development.

D. There is No Lawful Mechanism for Allocating Costs to Entities without a Service Relationship and Contractual Privity Between the Transmission Provider and its Customers.

The Commission's proposal to establish a mechanism through which transmission developers would recover costs from entities to whom they provide no transmission service is without precedent and unlawful. To begin with, LPPC notes that the Commission's reference to such a mechanism as involving "cost allocation" is a misnomer. In traditional ratemaking parlance, cost allocation involves the process of determining the appropriate portion of a utility's cost of service that will be borne by each class of customers. Importantly, the exercise

---

74 See, e.g., Northern Border Pipeline Co., 90 FERC ¶ 61,263 (2000); Williams Natural Gas Co., 79 FERC ¶ 61,055 (1997); Natural Gas Pipeline Co. of America, 76 FERC ¶ 61,142 (1996).


presumes that all entities to which costs are so "allocated" are customers of the utility performing the allocation. This is no less true of allocations on RTO/ISO systems (transmission providers in a direct relationship with their customers), than it is of vertically integrated utilities outside the RTO/ISO framework.

By contrast, the NOPR appears to contemplate a mechanism that would enable transmission developers to recover their costs from entities with whom they have no service relationship. The only nexus the Commission seems to foresee between the transmission developer and the entity to which costs are "allocated" is some showing of minimal conferred benefits, perhaps through the expectation that service may be taken on such facilities, even if service is not in fact provided. This, the FPA does not permit.

The FPA is structured on the assumption that rates subject to FERC approval are supported by a contractual agreement or tariff to take and provide service between a utility and its customers. Utilities filing for rate changes under FPA section 205 ask the Commission to approve changes in rates charged to their customers. Likewise, the Commission is authorized under FPA section 206 to direct utilities to charge revised rates to their customers if existing rates are found to be unjust and unreasonable. But the Commission's authority is, in all cases, based on the premise that a utility has a contractual and/or tariff relationship to provide service to its customers. Long-established Supreme Court precedent in the Mobile-Sierra cases supports this view. Commenting on that premise in Borough of Lansdale v. FPC, 494 F.2d 1104, 1113 (D.C. Cir. 1974), the court held that the purpose of the Mobile-Sierra doctrine is "to

subordinate the statutory filing mechanism to the broad and familiar dictates of contract law." It is, accordingly, well outside the Commission's authority to attempt to devise a mechanism whereby transmission developers would attempt to recover their costs from entities with whom they have no contractual or tariff relationship.

The Commission's attempt to defend its proposal on the ground that it routinely assesses costs to entities which do not agree to shoulder them voluntarily\(^\text{78}\) misses the point entirely. Of course, the Commission routinely sets rates that will be paid by customers that do not agree the rates are justified. But what distinguishes the proposal in this docket from all such cases is that the Commission routinely sets rates that will be charged by utilities to their customers. And even then, as the Supreme Court held in *Mobile-Sierra*, rate changes are further limited to the extent rates are subject to the parties' contract. Here, the Commission contemplates no such service relationship or contractual privity.

Nor does the Commission's reference to cases in which it has suggested a willingness to entertain filings for the recovery of costs associated with parallel path flow provide support.\(^\text{79}\) As the Commission itself indicates in the very same breath, it has never accepted such a filing, and has instead indicated that its general policy is to "encourage owners and controllers of transmission facilities to attempt to resolve parallel path flow issues on a consensual, regional basis."\(^\text{80}\) Of course, LPPC has no quarrel with the Commission encouraging parties to enter into mutually beneficial cost-sharing arrangements voluntarily. And LPPC can envision that regional planning fora may present an opportunity for parties to discuss such arrangements. But

\(^{78}\) NOPR at P 142.

\(^{79}\) Id. P 143.

\(^{80}\) Id. (citing *Southern California Edison Co.* 70 FERC ¶ 61,087 at 61,241-42 (1995)).
what the Commission cannot do is foist transmission developers' costs involuntarily upon entities which choose not to take service from those developers.

The Commission's reference to its decision in Midwest Indep. Transmission Sys. Operator, Inc. 109 FERC ¶ 61,168 at P 60 (2004) is equally unsupportive. There, the Commission directed the Midwest ISO and PJM to develop a methodology for allocating costs between the RTOs reflective of the fact that facilities built in one RTO may benefit customers in the other, who transmit power through both. The Commission cites the case for the proposition that costs incurred by one transmission operator may be allocated to another transmission operator on the strength of the fact that benefits are conferred. Yet, in that case, the resulting structure called for the ultimate transmission customers to be in contractual privity with both ISOs, while the mechanism for allocating costs between the ISOs (for eventual recovery from their customers) was a Joint Operating Agreement ("JOA"), through which costs were voluntarily shouldered by the ISOs. The case is, accordingly, wholly inapposite to the proposal on the table here, whereby the Commission suggests that it has the authority to permit transmission developers to allocate costs to unrelated entities with whom there is no contractual relationship, on the strength of a determination of presumed benefits.

81 Id. P 144.
82 Id.
83 The Commission asserts at NOPR P 144, n.156 that the JOA between MISO and PJM was irrelevant to its authority. According to the Commission, it "did not base the …directive on the existence of the Joint Operating Agreement, which Midwest ISO and PJM developed in order to comply with a previous Commission directive. Id. (citing Alliance Cos. 100 FERC ¶ 61,137, at P 48 (2002)). But the relevance of the voluntary nature of the JOA on this topic cannot be so quickly dismissed. In fact, at P 60 of 109 FERC ¶ 61,168, the Commission states: "We note that in their Joint Operating Agreement , the Midwest ISO and PJM have committed to develop such a methodology for allocating the costs of certain facilities…” Accordingly, the Commission's authority in this connection was not subject to challenge.
Finally, LPPC finds entirely unavailing the Commission's citation to the court's decision in *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004). The Commission cites the case for the proposition that "…courts have affirmed that the cost causation principle allows the Commission to allocate at least some types of costs to beneficiaries that are not customers of the public utility that is seeking to recover the costs in question." At issue in that case was the Commission's determination that Midwest ISO transmission owners should bear an administrative cost associated with the ISO's management of the transmission owners' bundled and grandfathered loads (and not only unbundled load). But the central point the Commission seems to miss in its reference to the case is that the Midwest ISO transmission owners are customers of the Midwest ISO. For that reason, what was before the Commission and the courts was a traditional cost allocation matter – *viz.*, the appropriate level of cost to be allocated a utility's customers, based on the benefits conferred. What the Commission is now contemplating, by contrast, is the distribution of costs to entities with no contractual relationship with the transmission developer.

**E. Assuming, Arguendo, that Costs Can be Distributed Without Regard to a Service Relationship, an Allocation of Costs Based on "Benefits" Must Nonetheless be Consistent with FERC's Statutory Authority.**

Putting to one side the foregoing discussion regarding the necessity of a contractual relationship, LPPC is heartened to see in the NOPR the Commission's recognition that its own decisions and those of the courts "…have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the 'cost causation' principle." LPPC urges the Commission to be clear, however, regarding the nature of the benefits that will justify

---

84 NOPR at P 146.
85 *Id.* P 139.
an allocation of costs, and on the necessary strength of the nexus between rates and benefits. LPPC is concerned that the Commission seems not to have set its sights higher than a determination that costs allocated to a beneficiary are "roughly commensurate" with benefits.

As to the nature of the benefits that the Commission may recognize in allocating costs, the Commission must acknowledge that the FPA limits its consideration to economic and reliability factors. These considerations – and none broader – are evident on the surface of the statute. FPA sections 205 and 206 authorize the Commission to set just and reasonable rates for non-discriminatory, reliable service, and nothing more. FPA section 215, of course, establishes a defined role for the Commission in connection with the promulgation and enforcement of reliability standards. As discussed above (supra, p. 21-22), the Supreme Court in *NAACP v. FPC*, 425 U.S. 662, has made it clear that the FPA "...is not a broad license to promote the general public welfare," but must instead be read in light of the "principal purpose" of the statute, viz., "to encourage the orderly development of plentiful supplies of electricity . . . at reasonable prices." *Id.*, 425 U.S. at 669-70. Moreover, as also discussed above, FERC has itself held that its authority under FPA sections 205 and 206 does not extend to the consideration of the environmental impact of its decisions. Accordingly, the benefits to which a legitimate cost allocation mechanism must be tied relate exclusively an adequate and economical supply of reliable electricity.

To be clear, LPPC recognizes that the demand for transmission facilities will reflect customer needs which may very well be driven by environmental directives. Responding to a state or federal RES, or potentially to a carbon control framework, the need for transmission to access renewable resources may very well become a factor in transmission demand. But the Commission must remain mindful that its mission lies in ensuring that the demand for
transmission service is met, regardless of the motivating factors. Accordingly, LPPC asks the Commission to confirm that the benefits relevant to any cost allocation methodology will relate exclusively to the availability of reliable transmission capacity at just and reasonable rates.

As to the strength of the nexus between rates and benefits, LPPC urges the Commission to be rigorous. The Commission draws the conclusion that costs need be no more than "roughly commensurate with benefits" from the decision in ICC v. FERC, in which FERC was faulted for failing to provide "even the roughest of ballpark estimates of...benefits" in support of its decision to roll into system-wide rates all new transmission facilities of 345 kV and larger. ICC v. FERC, 576 F.3d at 476. But the Seventh Circuit's rhetoric was designed to critique what the court took to be the Commission's cavalier attitude toward any needed evidence in support of its decision. While it is true that the courts have not required exactitude in the association of cost and benefits in support of a cost allocation mechanism, as the court in ICC v. FERC commented, the Commission has itself previously commented that "a claim of generalized system benefits is not enough to justify requiring existing shippers to subsidize [a new project]." LPPC respectfully suggests that assigning costs based on assertions of qualitative benefits and conjecture about the benefits of a new transmission facility over a period of decades would be speculative, and ultimately held to be arbitrary and capricious.

LPPC recognizes that in Southwest Power Pool, Inc., 131 FERC ¶ 61,252 (2010), issued the same day as the NOPR, the Commission eschewed reliance on a "quantitative study" of benefits, in favor of cost allocation based on "qualitative" benefits, including alleged benefits that might accrue to a particular party decades in the future. LPPC urges the Commission to be

86 Id. P 76, 85.
more rigorous here. As the court in *ICC* held, one cannot simply assume that transmission facilities over a certain size are generally beneficial, without reasoned operational analysis.

**F. Interregional Cost Allocation (NOPR at PP 170 – 178)**

LPPC's concerns with the Commission's approach to interregional cost allocation are similar to those raised with respect to the proposal governing regional cost allocation, discussed above. LPPC is encouraged by: (1) the Commission's indication that it is not proposing a uniform approach to cost allocation;\(^87\) (2) the Commission's indication that a transmission planning region that receives no benefit from an interregional transmission facility that is located in that region must not be involuntarily allocated any of the costs of that facility;\(^88\) and (3) the Commission's indication that the cost of an interregional facility must be assigned only to transmission planning regions in which the facility is located.\(^89\)

LPPC also supports the Commission in embracing of cost causation principles, but disagrees strenuously with the Commission's view that costs may be assessed to LSEs by transmission developers based solely on the LSE's identification as ostensible "beneficiaries" of a transmission project, notwithstanding the fact that there is no service relationship between the parties. For reasons argued above, LPPC does not believe such an assessment would be lawful.

As a practical matter, LPPC sees immense complications in the Commission's proposal that "public utility transmission providers located in each pair of neighboring transmission planning regions develop a mutually agreeable method for allocating between the two transmission planning regions the costs of a new transmission facility that is located within both

---

\(^87\) NOPR at P 175.
\(^88\) *Id.* P 174.
\(^89\) *Id.*
regions and that is eligible for interregional cost recovery pursuant to the region's interregional transmission planning agreement..." 90 LPPC envisions a planning process for interregional facilities driven with strife over cost allocation disputes, as parties seek, variously, to have their favored projects underwritten by others interregionally, or to evade such subsidization. Complicating that struggle is the fact that such discussions would take place in a factual vacuum – without reference to specific projects in the context of which the discussion might be given meaning with respect to the cost of potential facilities and their benefits.

Moreover, it is not at all clear how the Commission imagines that discussions "in each pair of neighboring transmission planning regions" will relate to one another. Indeed, there would be an interconnection-wide daisy chain of such discussions, all of which would have reverberations for one another, and all with complications of their own. Again, without reference to specific projects, LPPC sees the potential for endless debate. As difficult a matter as such discussion have been in the context of RTO operations (a subject with which the Commission has had recent and not altogether happy experiences), discussion among regions outside an RTO will inevitably be more complicated, as they involve utilities with disparate goals and needs, levels of investment, business models and regulatory masters.

In answer to all of this, LPPC urges the Commission to step back, in recognition of probability that the interregional allocation of costs is a topic on which consensus is feasible only in the context of specific projects proposed by project developers in order to satisfy identified market needs. Planning and cost allocation discussions are far likelier to result in the construction of necessary and efficiently utilized facilities when they reflect market pull, and

90 Id. P 172
not a regulatory push. The Commission's interest in having regions develop cost allocation principles in advance of such proposals puts the proverbial regulatory cart before the horse.

LPPC further adds that its members cannot at this time commit to entering into interregional agreements regarding cost allocation, for the reasons similar to those articulated above with respect to arguments regarding transmission planning. LPPC members will commit to participate in interregional discussions in order to develop a cost allocation mechanism. But without knowing what commitments and liabilities such agreements may include, LPPC members simply do not have the authority to commit their companies to an open-ended funding mechanism. As noted above, LPPC members are creatures of state and municipal governments, created by statute or municipal ordinance, and their authority to enter into binding arrangements is closely restricted consistent with their fiduciary responsibilities, and in a manner that will protect state and municipal sovereignty. LPPC members are restricted in their contracting practices by covenants in their financing arrangements, and cannot volunteer to enter into agreements that would, among other things, violate or jeopardize a private activity bond rule for purposes of section 141 of the Internal Revenue Code of 1986, 26 U.S.C. § 141, or any successor statute or regulation. With this in mind, LPPC members cannot commit to enter into agreements at this time, and cannot do so until substantial additional definition and assurance is provided.

V. Compliance Filing Schedule

LPPC does not believe the Commission's proposed one-year deadline for the finalization of interregional transmission planning agreements and interregional cost allocation

---

91 See supra, p. 29-30.
methods is realistic, when one considers the amount of work and extent of coordination these tasks call for, and the level of controversy likely to accompany the effort. These processes are likely to be particularly contentious if the Commission hews to its current proposal to reject approaches to regional and interregional cost recovery based on a requestor-pays approach. But even if that issue is resolved, the one-year deadline is substantially too aggressive. LPPC recommends that the Commission call for status updates on these matters in one year's time, potentially to be followed by further orders on a regional basis establishing a further reasonable timeline.

VI. The NOPR's Lack of Clarity in Several Key Areas Violates the Administrative Procedure Act.

In certain key respects, each addressed above, LPPC is concerned that the proposals in the NOPR do not provide clear indication of the Commission's intention. This is true in the following areas:

- It is not clear whether FERC proposes that regional and interregional plans will serve as the basis for future orders requiring utilities to undertake construction consistent with the plans. See supra, p. 16-19.

- It is not clear whether FERC proposes that regional and interregional plans would serve as the basis for orders compelling utilities to defer to non-incumbent utilities in connection with the construction of facilities needed for reliability purposes. See supra, p. 23-29.

- It is not clear what public policies must be incorporated in transmission plans, or in what manner such policies should be reflected. See supra, p. 19-21.

- It is not clear what rate mechanism FERC would employ to "allocate" costs incurred by non-incumbent transmission providers to entities with whom they have no service or contractual relationship. See supra, p. 43-47.

The Administrative Procedure Act, 5 U.S.C. § 553 ("APA") requires the Commission to provide notice of proposed rules adequate to afford interested parties a reasonable opportunity to participate in the rulemaking process. See Florida Power & Light Co. v. U.S., 846 F.2d 765,
A notice of proposed rulemaking must provide sufficient factual detail and rationale to permit interested parties to comment meaningfully. See id. Where a notice of proposed rulemaking fails to provide an accurate picture of the reasoning that led an agency to its proposed rule, parties will not be able to comment meaningfully on the agency's proposals. Connecticut Light and Power Co. v. NRC, 673 F.2d 525, 530 (D.C. Cir. 1982) ("CL&P").

VII. Municipal Participation in Transmission Planning and Cost Allocation

A. LPPC Members will Commit to Participate in Regional and Interregional Planning Processes, and in Regional and Interregional Cost Recovery Mechanisms where they Fairly Reflect Benefits Received.

Consistent with the commitments LPPC members made in connection with the implementation of Order No. 890, LPPC members commit here to participate in regional and interregional planning fora instituted pursuant to a rulemaking in this docket. As described at some length above, LPPC members are already participating extensively in the Order No. 890 regional processes, and are an intimate part of the broader interregional and interconnection-wide efforts already under way through EIPC and WECC auspices. Further, LPPC members will participate actively in regional and interregional discussions regarding proposals for transmission cost recovery. But, as also indicated above (supra, p. 29-30, 50-52), LPPC members cannot now commit to enter into binding agreements on these subjects.

As to the cost allocation mechanisms the Commission proposes to require, LPPC members will commit to consider any regional and interregional proposals that are advanced in regions of the country in which they do business. But they cannot agree now, without specific information identifying the costs and benefits associated with a given project or set of projects, to commit to funding. Such an open-ended commitment would violate the independent fiduciary responsibility LPPC members have shouldered on behalf of their customers.
B. Reciprocity Cannot be Expanded to Require Participation in Mandatory Region-Wide Cost Sharing, or to Require Municipalities to Alter Plans Deemed Necessary to Meet their Service Obligations.

At NOPR P 43, the Commission asserts that it "expects all public utility and non-public utility transmission providers to participate in the regional transmission planning and cost allocation processes proposed by this Proposed Rule." The Commission refrains from asserting its authority under FPA section 211A, but states that:

Reciprocity dictates that non-public utility transmission providers that take advantage of open access, including improved regional transmission planning and cost allocation, should be subject to the same requirements as public utility transmission providers.

At NOPR P 181, the Commission

…proposes that transmission providers that are not public utilities would have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their Safe Harbor tariff or otherwise satisfying the reciprocity requirements of Order No. 888 [citation omitted].

This requirement would expand dramatically the commitment that non-public utilities were asked to make pursuant to the reciprocity provisions in Order No. 888 and ensuing orders. It would also exceed the Commission's authority. As initially conceived in Order No. 888, reciprocity was thought to be a matter of fundamental fairness. As the Commission described it in Order No. 888-A: "It would not be in the public interest to allow a non-public utility to take non-discriminatory transmission service from a public utility at the same time it refuses to provide comparable service to the public utility."92 In Order No. 2004-A, the Commission clarified that that the service provided by a non-public utility need not be identical to the service

provided by an investor-owned utility, but rather need only be comparable to the service the non-public utility enjoyed for its own purposes.\textsuperscript{93}

With the enactment of FPA section 211A, this conception of the "comparable service" the Commission is authorized to require has been written into law. FPA section 211A provides that the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services —

1. at rates that are comparable to those that the unregulated transmitting utility charges itself; and

2. on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.

It is quite clear that this authority does not permit the Commission to compel a non-public utility to contribute funding for regional or interregional transmission projects, nor would it enable the Commission to exercise any authority over the transmission planning or construction plans of a non-public utility. Instead, the statute makes it plain that the Commission's authority is limited to compelling a non-public utility to provide transmission service, at rates and on terms and conditions that are essentially inward looking. One must ask how the service is provided by the utility to itself in determining the utility's obligation to third parties.

With this highly defined and circumscribed authority directly expressed by statute, the Commission does not now have the option of redefining the terms under which reciprocal service is provided in a manner that would give the Commission broader authority than Congress has directly provided. It is well-established that the Commission may not do

\textsuperscript{93} Order No. 2004-A, 106 FERC ¶ 61,220, at P 775 (2004). This view of "comparability" is the manner in which the open access tariff under Order No. 888 was initially conceptualized.
indirectly what it may not do directly. Accordingly, LPPC does not see that the Commission has the authority to compel non-public utilities to contribute to new regional or interregional cost allocation mechanisms, or to operate according to FERC-approved transmission plans directing the level and nature of transmission investment.

VIII. CONCLUSION

LPPC urges the Commission to craft the final rule in this proceeding, consistent with the foregoing argument.

Respectfully submitted,

_/s/ Jonathan D. Schneider___
Jonathan D. Schneider
Jonathan P. Trotta

STINSON MORRISON HECKER LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036
JSchneider@stinson.com
JTrotta@stinson.com
(202)785-9100

Attorneys for the
Large Public Power Council

September 29, 2010
Washington, DC

94 Sunray Mid-Continent Oil Co. v. FPC, 364 U.S. 137, 152 (1960); National Fuel Gas Supply Corp. v. FERC, 909 F.2d 1519 (D.C. Cir. 1990).
ATTACHMENT

PLANNING PROCESSES IN THE EASTERN AND WESTERN INTERCONNECTIONS TO WHICH LPPC MEMBERS ARE PARTIES.
Planning Processes in the Eastern and Western Interconnection to Which LPPC Members are Parties

In all regions of the nation in which LPPC members operate, processes are already in place or under development that address concerns highlighted in the NOPR and the Commission's interest in ensuring that needed regional and interregional transmission projects are studied and developed. The NOPR identifies alleged deficiencies in transmission planning without which the construction of new transmission facilities could be inhibited. The Commission also highlights a perceived lack of coordination between transmission planning regions, adding that more efficient transmission solutions may be identified through regional planning than through independent evaluation by transmission providers. While LPPC agrees with the Commission that coordinated transmission study and development is important, the NOPR appears to underestimate the extent to which transmission projects are presently being studied and developed on a regional level throughout the nation. In particular, LPPC members are taking meaningful steps to improve interconnection-wide transmission planning in order to facilitate the development of transmission facilities designed to interconnect new generation resources, and LPPC supports efforts already underway in both the Western and Eastern Interconnections that engage all stakeholders in regional planning. These coordinated efforts in each of the LPPC members' regions are detailed below.

A.  Eastern Interconnection Transmission Planning

1.  Coordinated Transmission Planning Processes in the Southeast

---

95 NOPR, P 35.
96 Id. P 39.
The Southeast has adopted a bottom-up transmission planning process that is driven primarily by State-regulated Integrated Resource Planning ("IRP") (including related mandatory Requests for Proposals ("RFPs") to meet generation needs identified in the IRP process). These State-jurisdictional IRP and RFP processes first identify the electric system's incremental needs (e.g., load growth) and then determine the most cost-effective and reliable resource and transmission solutions for meeting the future needs of the utility's consumers. As a result, State "public policy" considerations are affirmatively included in the IRP/RFP processes in the Southeast.

In the Southeast, the primary State public policy driver for generation, distribution, and transmission expansion remains the State-imposed "duty to serve" requirement, which generally requires State-regulated public utilities to maintain and expand their system on a least-cost and reliable basis to meet the needs of consumers. These and other public policy considerations are taken into account during the State-regulated IRP/RFP processes and are thereby embedded into transmission plans.

The results of a utility's State-regulated IRP/RFP process are combined with other firm transmission service commitments made by a utility's customers. This results in development of a transmission plan that accounts for a transmission owner's service to its native load and other firm transmission service commitments on its transmission system. Service requests made by a utility's customers represent decisions on how to best meet future energy needs, including those needs driven by federal and State "public policy" requirements, in an acceptable, least-cost fashion.

Once a utility has planned its system to accommodate the results of the IRP/RFP processes and its customers' OATT service requests, these results largely become the data inputs
for each utility's respective regional transmission planning process required by Order No. 890. Some utilities in the Southeast incorporate the results of the IRP/RFP and OATT processes into the Southeastern Regional Transmission Planning Process ("SERTP"), which, like the other regional planning processes in the Southeast, is a coordinated, open and transparent planning process that provides stakeholders with the opportunity and information to participate and confirm that regional transmission planning is being conducted on a non-discriminatory and comparable basis. Through the SERTP, the results of the underlying utilities' IRP/RFP and OATT processes are coordinated and combined to develop a transmission expansion plan for the entire SERTP region. Other regions in the Southeast construct similar regional transmission plans pursuant to their regional processes.

If any neighboring planning process may be impacted by a planning criteria identified in such a regional planning process, the potentially impacted region/transmission planning authority is contacted to determine if there might be a need for an interregional, \textit{ad hoc} coordination study between the affected regions. If the neighboring region agrees that it would be impacted by the projected limitation, a specific interregional coordination study is initiated. Once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the regions' transmission expansion plan.

Once the SERTP plan and other Southeast regional transmission plans are completed, the SERC Reliability Corporation's ("SERC") transmission planning committee (which is composed of representatives from the transmission-owning and operating utilities in the Southeast) analyzes the various sub-regional and regional transmission plans to facilitate

\footnotesize{\textsuperscript{97} The SERTP was a pre-existing regional transmission planning process that several Southeast utilities used to comply with Order No. 890’s Attachment K planning requirements.}
simultaneous interregional feasibility and consistency in models and data.\textsuperscript{98} This SERC-wide analysis effectively rolls the regional transmission plans into a set of unified, interregional SERC transmission base cases. If the SERC-wide reliability model projects additional concerns that were not identified in the underlying regional studies, then the impacted transmission owners may initiate one or more \textit{ad hoc} interregional coordination studies to better identify the projected concern. The resulting reliability enhancements that might be identified are then incorporated into the affected region's expansion plan. "Accordingly, concerns identified at the SERC-wide level are 'pushed-down' to the transmission owner level for detailed resolution."

Transmission planners in the Southeast further coordinate on an annual basis with the other NERC Regional Entity transmission planners and planning authorities in the Eastern Interconnection to produce the interconnection-wide, NERC Eastern Interconnection Reliability Assessment Group ("ERAG") Multiregional Modeling Working Group ("MMWG") base cases that provide the foundation for essentially all subsequent transmission planning studies in the Eastern Interconnection.

Regional planning processes throughout the Southeastern are further integrated through the Southeast Inter-Regional Transmission Participation Process ("SIRPP"),\textsuperscript{99} an annual process developed by Southeast transmission providers to more fully address Order No. 890's regional participation principle. SIRPP complements the regional planning processes of participating transmission owners in the Southeast by consolidating data and assumption developed at the regional level and using that information to develop planning models. SIRPP ensures

\textsuperscript{98} While SERC provides the organizational/ committee structure that is used by the NERC-registered planning authorities in its footprint to produce the annual SERC-base cases and also performs a long-term reliability assessment for the SERC footprint, SERC itself performs no transmission planning.

\textsuperscript{99} The SIRPP was established pursuant to a request from FERC Commission Staff during the initial Attachment K development process.
consistency in the planning data and assumptions used in local, regional and interregional planning processes.

SIRPP facilitates the development of economic planning studies that involve impacts on multiple systems between regional planning processes. Stakeholder requests for regional economic planning studies submitted through a SIRPP participant's Attachment K process that involves transmission providers across multiple interconnected systems, are consolidated and evaluated as part of the SIRPP. Stakeholders may also request interregional economic planning studies directly through the SIRPP. Coordination of interregional economic planning studies through SIRPP is conducted by a study coordination team comprised of participating transmission owner staff that develops study assumptions, performs model development and other coordination efforts with stakeholders and impacted external planning processes. The study process also involves developing solution options and evaluating stakeholder-suggested solution options, and developing a report upon completion of all studies. The final report(s) is distributed to all participating transmission owners and stakeholders. SIRPP establishes detailed time frames and procedures for coordination with stakeholders in the development of interregional economic planning studies that emphasize transparency in the SIRPP study process. SIRPP procedures also provide clearly-defined opportunities for stakeholders to comment and provide input regarding draft reports.

Equally important to planning in the Southeast, SIRPP enables participating transmission owners to review regional data, assumptions and assessments being performed on an interregional basis.

LPPC members of the Southwest Power Pool (“SPP”) Nebraska Public Power District (“NPPD”) and Omaha Public Power District (“OPPD”) are active participants in the planning

These regional and interregional planning processes are further supplemented by the Eastern Interconnection Planning Collaborative ("EIPC") and the Eastern Interconnection State Planning Coalition ("EISPC"), as discussed below.

2. **Eastern Interconnection-Wide Planning: EIPC**

The planning processes in the Southeast and throughout the Eastern Interconnection are further supported and coordinated through the EIPC – a broad-based, transparent and collaborative process initiated by a coalition of planning authorities representing the entire Eastern Interconnection. The EIPC was instituted to address any otherwise unidentified alternatives to improve the efficiency and effectiveness of interregional transmission upgrades, and allows states in the Eastern Interconnection to participate in interconnection-wide planning efforts. In addition, the EIPC, with input from EISPC and stakeholders, evaluates various future scenarios that can inform policy makers and stakeholders in their future decision-making pertaining to resource and transmission commitments.

The EIPC facilitates interconnection-wide planning efforts and enables inputs from various stakeholders including state and federal policy makers, consumer and environmental interests, transmission planning authorities, and market participants generating, transmitting or consuming electric energy within the Eastern Interconnection. The EIPC builds upon regional transmission expansion plans developed yearly by regional stakeholders and planning

---

100 The EIPC is the recipient of DOE funding.
authorities to provide a coordinated interregional analysis for the entire Eastern Interconnection. This interconnection-wide planning process is guided by an open and transparent stakeholder process.

The EIPC enables planning authorities in the Eastern Interconnection to model the impact on the grid of various policy options determined to be of interest by state and federal policy makers and other stakeholders. The EIPC ultimately produces an interconnection-wide review of existing regional plans and transmission options associated with various policy options. This information serves as critical inputs into regional processes that build into regional and sub-regional models the efficiencies and improvements identified in the EIPC process.

The underlying principle of the EIPC is that fully coordinated interconnection transmission analyses is best accomplished through an approach that builds and expands on existing regional processes and planning expertise. EIPC, then, directly addresses any concerns the Commission might have about a perceived lack of coordinated planning between regions and over the seams of existing planning regions throughout the Eastern Interconnection. LPPC supports this model for identifying and developing planning efficiencies across the entire Eastern Interconnection.

**B. Western Interconnection Transmission Planning**

The Western Interconnection has a long history of broad regional and interregional cooperation under the Western Electricity Coordinating Council ("WECC")\(^\text{101}\) umbrella.

\(^\text{101}\) WECC is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. In addition, WECC assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in its bylaws. WECC's service territory extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states.
Transmission planning and expansion throughout the Western Interconnection is coordinated through numerous regional and sub-regional planning groups ("SPGs") that conduct transmission planning on a more local, sub-regional basis (see Figure 1). In addition to their local transmission planning processes, LPPC members engage in joint regional transmission planning with other transmission providers and stakeholders throughout the Western Interconnection through their participation in, among other regional and sub-regional planning groups, WestConnect\textsuperscript{102} and its Colorado Coordinated Planning Group ("CCPG"),\textsuperscript{103} ColumbiaGrid, the California Transmission Planning Group ("CTPG") and, ultimately, WECC.

\textsuperscript{102} WestConnect is an unincorporated association composed of utility companies providing transmission of electricity in the southwestern U.S. The WestConnect footprint encompasses the state of Arizona, Colorado, New Mexico, Nevada, and parts of California, Texas, South Dakota and Wyoming. Three major sub-regional technical planning working groups operate within the WestConnect footprint: the Southwest Area Transmission Planning Group, the Sierra Sub-Regional Planning Group, and the Colorado Coordinated Planning Group ("CCPG").

\textsuperscript{103} The CCPG is a joint, high voltage transmission system planning forum for the purpose of assuring a high degree of reliability in the planning, development, and operation of the high voltage transmission system in the Rocky Mountain Region. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region of the WECC. See http://www.westconnect.com/planning_ccpg.php
1. CCPG and WestConnect Coordinated Planning

LPPC members are active participants in the CCPG, a sub-regional process tasked with coordinating transmission planning information and sharing updated on active transmission projects. The CCPG sub-regional planning group provides an open forum where stakeholders interested in transmission system planning within the CCPG footprint can participate and obtain information regarding base cases, plans and projects, and provide input or express outstanding needs related to the transmission system. The CCPG promotes sub-regional transmission

---

planning and development to ensure that participants' transmission plans are coordinated to maximize use of the existing transmission system and identify transmission expansion alternatives that most effectively meet future needs.

Transmission providers participating in CCPG submit their transmission plans for inclusion in CCPG planning activities, and further support the CCPG process through development of study assumptions, supplying system data, execution of studies when available, and review of study results and reports. Transmission plans submitted by CCPG participants are coordinated within CCPG, incorporated into CCPG transmission studies and plans, and coordinated between neighboring sub-regional planning groups through the WestConnect transmission plan process.

The CCPG facilitates stakeholder participation in its sub-regional planning process both through stakeholder attendance at CCPG meetings and through direct input to transmission providers.

WestConnect provides to its members, including LPPC members participating in the CCPG, increased coordination of study efforts between all SPGs within the greater WestConnect planning area. WestConnect's transmission provider members coordinate and actively participate in the WestConnect planning process pursuant to defined objectives and procedures for regional transmission planning, and integrate their transmission plans with plans of other WestConnect participants into a single ten year regional transmission plan.

This process is achieved by coordinating, developing and updating common base cases, as needed, to be used for all study efforts within the SPGs, and ensuring that each plan adheres to the common methodology and format developed by the WestConnect SPGs. Transmission
providers also submit any studies and pertinent financial, technical and engineering data to CCPG for review and comment, which is then used within the WestConnect planning process.

Stakeholders participate in the WestConnect planning process through participation in public stakeholder meetings or by providing input to the transmission provider that is conveyed to WestConnect. Both WestConnect and CCPG have transparent processes for stakeholder input, available through their respective websites.

WestConnect's coordinated planning process promotes consistency in the data, assumptions and models used in SPG planning activities. SPGs within the WestConnect footprint, assisted by the WestConnect planning manager, coordinate with other Western Interconnection transmission providers and their SPGs through WECC's Transmission Expansion Policy Planning Committee ("TEPPC"), as discussed below.

2. ColumbiaGrid

LPPC members in the Pacific Northwest are active participants in ColumbiaGrid and, along with other members of ColumbiaGrid, are signatories to the ColumbiaGrid Planning and Expansion Functional Agreement ("PEFA"), which provides for sub-regional transmission planning among its members. ColumbiaGrid's transmission planning process is designed to facilitate a "single-utility" approach to transmission planning among its members, under which the transmission facilities of various transmission providers are planned as if owned by a single utility. ColumbiaGrid actively develops a single transmission plan for parties to the PEFA that own or operate transmission facilities, and annually performs a system assessment of the interconnected transmission systems in the Pacific Northwest that is focused on determining the ability of each transmission owner or operator to serve, consistent with all appropriate reliability standards and criteria, its network and native load obligations and other existing long-term firm
transmission obligations anticipated to arise over the ten-year planning horizon. If this process reveals a projected inability for a transmission owner or operator to meet its existing obligations over this planning horizon, ColumbiaGrid forms study teams to develop a plan to resolve the need. These study teams facilitate collaboration among transmission owners, operators and other interested parties, to study and plan on a coordinated basis various types of projects, as defined in the PEFA.

On a regional level, ColumbiaGrid coordinates with neighboring planning entities throughout the Western Interconnection through its active, ongoing participation in the WECC sub-regional and regional processes. ColumbiaGrid is a SPG in the Western Interconnection and coordinates with other SPGs and with WECC. As part of this process, ColumbiaGrid meets regularly with other SPGs in joint meetings held at least three times annually, that focus on reviewing and coordinating study activities, development of WECC base case assumptions and requests, sharing of planning information, and coordination of requests to WECC for economic studies. ColumbiaGrid's model for sub-regional transmission planning has resulted in a high degree of coordination among transmission systems in the Northwest, including LPPC members' systems. ColumbiaGrid's regional transmission planning process has vetted several transmission plans that impact the systems of multiple transmission providers and, as part of the sub-regional planning process, has formed study teams consisting of non-PEFA parties that develop focused transmission plans to address complex transmission issues in specific areas, such as the Puget Sound area in Northwest Washington. Specific transmission plans such as these are developed by teams open to all interested parties, regardless of whether they are ColumbiaGrid signatories.
3. CTPG

LPPC members in California are also participating in the CTPG, which performs technical studies using California's Renewable Energy Transmission Initiative ("RETI") conceptual transmission plan as a starting point to help identify transmission projects needed to meet state-wide renewable energy goals. The CTPG includes California transmission owners and operators and functions to coordinate statewide transmission planning in California. The CTPG is a forum for conducting joint transmission planning and coordination to meet the needs of California consistent with Order No. 890, as well as to develop a state-wide transmission plan to meet California's 33% by 2020 renewable portfolio standard goal. Similar to the SIRPP process in the Southeast, the CTPG is the result of ongoing discussions facilitated by FERC to address transmission needs. The CTPG develops annually a California transmission plan that incorporates the needs of its participants, and identifies opportunities for joint transmission development projects.

4. Western Interconnection-Wide Planning

WECC's role in regional and interregional transmission planning is one of coordination, facilitation and analysis. WECC coordinates regional planning activities with and among SPGs, state and provincial agencies, balancing authorities and transmission providers, and provides impartial information to planners and decision makers in the Western Interconnection. In this way WECC supports the Order No. 890 and 890-A planning principles for transmission providers in the Western Interconnection.

WECC coordinates planning in several ways, including developing interconnection-wide databases for transmission planning analysis such as power flow, stability and dynamic voltage stability studies, as well as databases for reporting the status of all planned projects.
throughout the Western Interconnection. WECC also coordinates planned and proposed projects through its Procedures for Regional Planning project review. The process of identifying transmission needs and evaluating the impact of potential transmission solutions within the WECC framework is managed by two distinct processes: (1) TEPPC's regional expansion planning, which conducts Western Interconnection-wide economic studies in a transparent and open stakeholder process; and (2) the Planning Coordination Committee's ("PCC") path rating process, which ensures that new projects will have no adverse impacts on existing facilities or approved projects.

The WECC TEPPC provides two main functions in the planning process. Firstly, the TEPPC assists to develop and maintain an interconnection-wide economic planning study database that is widely available throughout the West. Secondly, the TEPPC performs economic planning studies that include studying transmission customer high priority economic study requests as determined by an open stakeholder process at the TEPPC level. LPPC members participating in WECC's interregional planning process report that TEPPC's open-season study request process involves data and model validation work through workgroup meetings to ensure that information and modeling techniques are coordinated. TEPPC is further charged with assisting the Western Governors' Association Renewable Energy Zone Initiative.

TEPPC's planning activities quantify future transmission congestion based on load, resource, and transmission scenarios provided by stakeholders through an open-season study request process. Based on the identified congestion, TEPPC also examines the impact of

---

105 The Western Governors' Association is a non-partisan organization of 19 states and three U.S. territories in the western region of the United States, covering a wide range of policies including an energy and transmission initiative.
various transmission expansion scenarios. These activities and the resulting analysis serve as guidance for future transmission system needs. While TEPPC does not propose transmission projects, WECC provides information and analysis through its study process which further facilitates the evaluation of proposed solutions. This in turn provides information and inputs for regional and sub-regional processes. In this way, WECC supports a bottom-up/top-down approach to planning in the Western Interconnection that ensures that accurate, quality data and stakeholder-vetted assumptions and models are available for use in planning processes throughout the region.

As part of a bottom-up process, TEPPC gathers data through an open-season study request process, which is then coupled with data and models from multiple sources, including the WECC load and resource reporting activities, SPG plans, and state and provincial activities. In its top-down planning process, information gathered by WECC is analyzed in open TEPPC workgroup meetings, and then used to determine future possible transmission congestion and solutions. WECC then makes this information, and resulting analysis, publically available through reports, models and data files. This information and analysis ultimately forms the basis for transmission planning processes developed throughout the Western Interconnection.

WECC's transmission expansion planning processes are undergoing significant expansion and refinement to better evaluate the reliability implications of state renewable energy policies, proposed greenhouse gas reduction policies, and the changing mix of generation and demand side resources. By way of example, TEPPC has undertaken more sophisticated studies to better understand how transmission needs compare for various state renewable energy preferences (e.g., local preference versus least cost). In this manner,
interregional transmission planning throughout the West already incorporates policy-based needs and requirements into expansion plans, consistent with FERC's objectives.

The above comprehensive regional, sub-regional and interregional/interconnection-wide processes facilitate and promote effective stakeholder involvement and enable coordination among planning entities to provide consistency of data, assumptions and models being used in planning activities at all levels. Regional and sub-regional plans in the East are coordinated and evaluated actively at the regional level through bottom-up planning, and through the EIPC. In the West, these plans are coordinated and studied by all SPGs and at the WECC TEPPC level.

LPPC supports this regional, sub-regional and interregional approach to transmission planning, and believes that maintaining planning at these levels allows and will continue to allow for effective planning and coordination for future transmission development. Imposing a new framework on top of these already-existing structures would serve to thwart the coordinated progress being made to date, and would complicate regional and sub-regional planning efforts that are otherwise effectively coordinating, studying and implementing needed transmission solutions.
2008: our goal
We will reduce, offset or displace more than 15 million metric tons of greenhouse gas emissions per year by 2020.

2010: our progress
We have achieved more than half of our goal by reducing, offsetting or displacing nearly 8 million metric tons of greenhouse gas emissions.
Letter from John W. Rowe

FALL 2010

This report marks our second annual progress report on Exelon 2020: a low-carbon roadmap, our plan to reduce, offset or displace our company’s 2001 carbon footprint by the year 2020. We developed this initiative in 2008 believing that a clean energy portfolio is both good public policy and good business.

Two years later, Exelon is halfway to our goal of abating 15.7 million metric tons of carbon dioxide (CO2) emissions per year. This is equivalent to taking about 1.5 million cars off the road every year. The details of our accomplishments can be found on pages 12-26 of this report and come from throughout the company. Given this progress, I am confident that we will achieve our 2020 goal and will do so in a way that will create increasing value for Exelon’s shareholders.

We are very proud of Exelon 2020. It reflects the unique contribution of our fleet of 17 nuclear reactors and the planning we began in 1998 to prepare for increasing environmental limitations on coal. It underscores the value of Exelon’s assets in a carbon-constrained, clean energy world. Exelon 2020 serves as Exelon’s resource plan, as a guide to our investment decisions and as a framework for our public policy advocacy. It tells us which actions have the highest opportunities for our shareholders while also providing our customers with reliable, clean energy at the lowest costs. Exelon 2020 tells us which projects are more or less effective in reducing carbon and more or less economic. In short, Exelon 2020 serves as the business strategy that cements Exelon’s value as the premier low-carbon company in the U.S. utility industry.

Our record makes clear that we are committed to a clean, low-carbon energy supply. However, we are equally committed, especially in today’s challenging economy, to avoiding unnecessary costs. Exelon 2020 is a roadmap for advancing market-driven innovation and economic options. Our clean energy investments will spur the creation of jobs within Exelon and at hundreds of supplier companies. But there is no need to promote clean energy subsidies at any cost. At Exelon we are making new clean energy investments while minimizing the costs our customers will pay for a clean energy future.
Our business strategy, as synthesized by Exelon 2020, is predicated on the following principles.

A clean energy portfolio, based on sound economics, creates compelling value. While climate legislation is unlikely in the near future, fossil fuels face a variety of challenges. The U.S. Environmental Protection Agency (EPA) is under statutory mandates to increase the regulation of hazardous air pollutants and coal combustion byproducts. Inefficient, higher-polluting coal plants will become more expensive to operate, creating incentives for these supply sources to be retired. Abundant supplies of natural gas, coupled with other clean energy options, will enable the economic and reliable replacement of that capacity where needed. This transition can be accomplished while maintaining electric system reliability and protecting consumers from excessive rates.

The United States is moving toward a lower-carbon, less-polluting society, but in uneconomic fits and starts. We now have a patchwork of low-carbon energy policies at the federal and state levels. Prominent among them are mandates for utilities to buy renewable power; tax credits for wind and solar power; loan guarantees for new nuclear plants and other clean energy options; and funding for clean coal. Yet the economics underlying Exelon 2020 – based on projects we have considered in the markets in which we operate – tell us that current policies largely promote the expensive options and neglect the cheapest ones. (The economics are depicted in the Exelon Supply Curve on page 6.) Selecting generation technology based on short-term perspectives does not work for consumers and does not work for utilities. New wind power currently requires a carbon price of $80 to $120 per metric ton to become economically break-even, new merchant nuclear plants require $100 per metric ton, clean coal (if the technology can be proved) requires $500 per metric ton, and solar requires as much as $675 per metric ton.

Each $10 per metric ton of carbon increases retail electricity prices by roughly an incremental $0.01 per kilowatt hour. Becoming lower carbon today by relying too much on wind, new nuclear plants, solar energy and clean coal could double the retail electricity price in many markets. Considering the nascent state of the economic recovery and the sobering federal budget outlook, those are costs that we should not pay. There are more affordable ways to ensure a clean energy portfolio.

Pursuing the cheapest options offers the greatest benefits for our customers, shareholders and the economy. Exelon’s primary actions to reduce our carbon footprint (shown on the left side of the Exelon Supply Curve on page 6) include: retiring four inefficient, carbon-intensive fossil generating units in Pennsylvania; customer energy efficiency programs at ComEd and PECO; and uprates at our existing nuclear plants. These initiatives are responsible for more than 75 percent of our targeted carbon reductions. Projects like energy efficiency programs will save our customers money, while investments in some nuclear uprates are value-creating opportunities for Exelon’s investors and provide cheap, low-carbon energy to the electricity markets we serve. When more capacity is needed, natural gas is the lowest-cost option. By prioritizing these projects based on their economics, Exelon 2020 represents a business strategy that delivers superior value to Exelon’s customers and investors while also helping to eliminate our carbon footprint and reducing conventional pollutants.
Exelon 2020 is not static; it is a directional roadmap. The Exelon Supply Curve that shows the costs of carbon reduction is a snapshot in time. It changes with the price of natural gas and as the supply of and demand for electricity changes. Since we first introduced the Supply Curve in 2008, the order of the options has been relatively constant, but the curve has steepened and many options have become more costly. For now, the curve demonstrates that there is no large-scale need to build new generation in our markets, and that when we do need to build, there will be clean generation that is economic. Undoubtedly, both demand and costs will change further in the coming years. Exelon 2020 provides a comprehensive view of all the options. This is a strategy that, based on its real-time flexibility and market orientation, will serve our customers, markets and investors well.

To Exelon, the question facing the United States is not whether it should reduce air pollution and carbon emissions, but how to do so at the lowest possible cost. Our Supply Curve is significant for the entire electric industry and emerging national energy policy.

- Extrapolating our results to the industry as a whole tells us that a major priority should be to replace older, inefficient, pollutant- and carbon-intensive coal plants with a combination of cost-effective solutions. These include reducing consumption through energy efficiency and demand response, and adding capacity through the lowest-cost generation alternatives.

- New natural gas discoveries promise a more abundant supply of this critical low-carbon fuel, fundamentally challenging the economics of other resources including renewables, new nuclear, and coal with carbon sequestration. While fuel diversification remains important and continued research and development-scale investment into these other technologies remains vital, the cheapest way of meeting new demand for electricity – when that new demand materializes – is currently natural gas combined-cycle and peaking units.

- Investments in new electricity generation are not required in our markets until we see EPA action on pollutants that forces coal retirements. It is wise to have an energy policy that keeps all options alive – including new nuclear plants, solar and clean coal. But large generation build-out at this time will give customers much more power than they need at prices they should not have to pay.

A price on carbon remains essential to ensuring that national efforts to address climate change are undertaken at the lowest possible cost. Without a price on carbon, the United States will overlook many cost-effective solutions while continuing to spend billions on more speculative, less reliable and more expensive ones. Nonetheless, the pending suite of EPA regulations provides ample strategic and economic support for Exelon 2020. As shown in our analysis on pages 8 and 10, EPA regulations could help wholesale market participants in the PJM region significantly reduce CO2 and other emissions over the next 10 years at a real cost lower than the inflation-adjusted price paid for power in 2008.

With Exelon 2020 as our guide, we will continue to work in Washington and our state capitols for an economically rational approach to ensuring clean, reliable and secure power at the lowest possible cost.

Yours sincerely,

John W. Rowe
Chairman and CEO
Uncertainty and change

The global recession has challenged our society’s ability to combat climate change while managing other priorities. With the economy recovering slowly, electricity demand and power prices remain low. There is much uncertainty around whether and how the U.S. government will act to increase the reliability of, and decrease the pollution from, our nation’s power generation fleet.

But we do know that, with the right public policy signals, the country can begin the path to a clean energy portfolio through energy efficiency and using its abundant natural gas resources in place of carbon-intensive coal plants.

In the absence of a national energy policy, the United States has undertaken a variety of uncoordinated actions to address clean energy, like renewable portfolio standards, federal loan guarantees, tax credits and other efforts. However, these programs amount to a patchwork that obscures the potentially high cost of dealing with clean energy and climate change in this way.

Although new electricity supply may not yet be needed, the EPA will put the country on a faster path as it writes new rules that will regulate emissions of sulfur dioxide, nitrogen oxide, mercury, acid gases and other hazardous pollutants and coal plant byproducts. These regulations will inevitably lead to the retirement of some aging and inefficient coal plants and the selection of new generation sources.

Exelon is confident that these regulations can be implemented in ways that ensure continued grid reliability, reduce air pollution and avoid unnecessary cost increases. While some may argue that a carbon policy or air pollution regulation is too costly, the cost of inaction or poorly constructed incentives is far greater.

Partners in Change

As a member of the U.S. Climate Action Partnership, Exelon has joined with more than two dozen corporations and NGOs to offer recommendations for addressing climate policy issues. Our relationships with Resources for the Future, the Pew Center on Global Climate Change Business Environmental Leadership Council and Ceres allow us to engage with organizations that share our drive to effectively address the need for cleaner energy.

Exelon’s sponsorship of the MIT Joint Program on the Science and Policy of Global Change supports needed research for informing sound policy development. Within our own industry, we are engaged with organizations such as the Clean Energy Group and the Edison Electric Institute to build consensus for congressional enactment of a national comprehensive climate policy.

We are proud of having been named to the Dow Jones Sustainability North America Index for the past five years and included on the Carbon Disclosure Project Leadership Index five of the past six years, recognizing Exelon for its actions to address climate change and other steps to become a sustainable enterprise.
Science of climate change

Climate change is real. Two years ago, acceptance of the scientific foundation behind climate change seemed settled. However, errors and arrogance by a few members of the United Nations’ Intergovernmental Panel on Climate Change have caused some to broadly indict the scientific consensus. The National Academy of Sciences (NAS), our nation’s preeminent scientific research organization, has done extensive work to confirm that the climate is changing and that human activity is a major contributor.

In May 2010 the NAS issued a series of new reports that represents that body's most comprehensive study of climate change to date. NAS confirms that climate change is occurring, is caused largely by human activities, and poses significant risks for – and in some cases is already affecting – a broad range of human and natural systems.

The NAS finds that “global warming is closely associated with a broad spectrum of other climate changes, such as increases in the frequency of intense rainfall, decrease in snow cover and sea ice, more frequent and intense heat waves, rising sea levels and widespread ocean acidification.” Observations of the earth’s surface temperature over the past 100 years as compiled from diverse sources demonstrate that the most significant changes have taken place in the most recent decades (see figure 1). Not all effects of climate change on the earth’s processes are fully understood or captured in current climate models. In aggregate, the effects could contribute to increasing the consequences of climate change. The NAS concludes that the longer the nation waits to address the climate change challenges, the more expensive it will be.
Updating our Supply Curve analysis

We have prepared our Supply Curve of Greenhouse Gas (GHG) Abatement Opportunities this year for the third time. The Supply Curve is a snapshot of the relative economic merit of alternatives to abate greenhouse gases in the electricity sector. Many factors that drive the Supply Curve have changed since we first released it in 2008, when prices for electricity were climbing quickly as a result of rising natural gas prices and high expectations for future electricity demand. Today, we see demand for electricity slowly recovering from the recession and natural gas prices holding at levels well below their historic highs in 2008. As a result, this year’s Supply Curve is based on two primary assumptions:

• Electricity demand grows at an average of 0.6 percent per year, well below historical averages, reflecting expected installations of energy efficiency and smart grid measures in the coming years.

• Natural gas prices average $7 per mmbtu (in 2016 dollars), reflecting the economic impact of the country’s vast shale gas resources.

The 2010 Exelon Supply Curve (see figure 2, page 6) reinforces the conclusions we derived from previous versions. On the left side of the curve (-$50 to $0 per metric ton), we see that the customer energy efficiency programs at ComEd and PECO and Exelon Generation’s nuclear uprates remain clear winners from both environmental and economic perspectives. They have weathered downward changes in power prices precisely because they are low-cost solutions.

One notable addition to the far left (i.e., most economic) side of the curve is the retirement of our coal units at Eddystone and Cromby, our two Eisenhower-era generating facilities in Pennsylvania. Continued operation of the units is not economically justified in light of expected power prices, even before considering a price on carbon. We address the broader issues around coal retirements later in this report.

Moving to the middle of the curve ($0 to $50 per metric ton), new natural gas combined-cycle plants continue to be the most economic new-build option. This position has been accentuated as natural gas prices have fallen. However, with demand low and many power markets still saturated with generating capacity, new plants are simply not needed. Demand growth or some other catalyst will be necessary to trigger the need for new generation.

Farther right on the curve ($75 per metric ton and above), we see many of the supply options discussed by policymakers and the media – wind, new nuclear, solar and coal with carbon capture and sequestration (CCS). While these options may cost-effectively mitigate the impacts of climate change over the long term, they are expensive ways to abate GHG emissions today. The required carbon prices for these options have risen since last year due to the weakening fundamentals described above. One exception is solar, which we expect to experience significant cost reductions in coming years, even as it is currently one of the highest-cost ways to abate GHG emissions.
Figure 2
2010 Supply Curve of Exelon’s Greenhouse Gas Abatement Opportunities

Note: Emissions reduction estimates for new generation capacity represent emissions reduced in the market as a result of the project less emissions introduced due to the project. New nuclear plant assumes 50% ownership of two 1,455 MW units.

Technology cost assumptions (in 2010 $/kW):
- Combined-cycle gas turbine: $1,300 - $1,700
- Wind: $2,000 - $2,500
- Nuclear: $5,000 - $6,500
- Clean coal with CCS: $5,500 - $6,500
- Solar photovoltaic: $5,000 - $6,000
Many of these “new build” options appear expensive because expectations of future power prices have fallen since 2008. But another factor is playing a major role in preventing the orderly, economic clean-up of the country’s power generation: our industry is generally oversupplied with generation capacity. As a result, new low-carbon investments must compete with existing power plants whose costs have already been “sunk.”

Older, inefficient, high-emitting coal plants are the main source of this overcapacity. These plants would face pressure to retire in a world with a price on carbon, but this solution may not come soon. Instead, it appears increasingly likely that the EPA will force some of these plants out of service through new regulations of sulfur dioxide, nitrogen oxide, hazardous air pollutants (HAPs) like mercury, and coal combustion byproducts, among other pollutants.

**Taking a broader view – the PJM Cost Curve**

To understand the impact of EPA’s actions, we expanded our analysis beyond Exelon’s options and took a broader look at how the industry may respond. We also examined the options on a cost-per-megawatt-hour basis rather than on a carbon price basis. The result of these efforts is the PJM Cost Curve (see figure 3, page 8). It represents the levelized cost of energy (in 2016 dollars per megawatt-hour and adjusted for the market value of the generation’s production profile) of a variety of options available to all market participants to clean the generation supply in the PJM Interconnection. PJM serves 13 states and the District of Columbia, a region that includes more than 51 million people. It is the primary regional wholesale power market in which Exelon operates.

Between now and 2015, a variety of EPA rules and regulations impacting coal-fired plants will take effect:

- The Clean Air Transport Rule (CATR), regulating sulfur dioxide and nitrogen oxide emissions and requiring pollution control retrofits. The rule was proposed in July 2010.
- The revised Clean Air Act regulations defining maximum achievable control technology (MACT) for HAPs, including mercury, other metals and acid gases and requiring installation of emissions control technologies. The rule is expected in spring 2011.
- A proposed Coal Combustion Residuals rule that will impose new standards and controls on coal ash was published in June 2010.
- The EPA also continues to have the authority to regulate greenhouse gases, including CO2, under the Clean Air Act.

We have made assumptions around the costs coal generators will face due to forthcoming EPA rules and regulations, including the impact of the proposed CATR and the expected MACT standard to control emissions of HAPs.
Figure 3
Levelized Cost of Energy for GHG Abatement Options in PJM

Note: Adjusts for the market value of the generation’s reliability and production profile.
Technology cost assumptions (in 2016 $/kw):
Combined cycle gas turbine: $1,900 - $2,700
Wind: $2,000 - $2,500
Nuclear: $5,000 - $6,000
Clean coal with CCS: $5,500 - $6,500
Solar photovoltaic: $3,000 - $4,000

Solar PV: $375 / $210 with incentives
Coal Retirements
Energy Efficiency
Nuclear Uprates
Coal-to-Gas Switch
Solar Photovoltaic
New Natural Gas Plant
Wind Power
New Nuclear Plant
Clean Coal with CCS
White line represents price after including effects of tax incentives or loan guarantees
The PJM Cost Curve shows us the relative total cost of alternatives and drives us to a number of important conclusions:

- Thirteen gigawatts (GW) of coal capacity can retire in PJM in coming years with a replacement cost of less than $65 per megawatt hour (MWh). Some of these plants will retire due to market conditions (4 GW, the first purple bar), as exemplified by our decision to retire our Eddystone and Cromby units. Other plants will retire due to the MACT standard (9 GW, the second purple bar). The retired coal plants can be replaced in the near-term by the existing resources in PJM, but by the second half of the decade the region would require new supply. Additional coal plants could also be replaced by new PJM generation, but at much higher costs (represented by the third and fourth purple bars). To put these numbers in context, PJM currently has about 68 GW of operational coal capacity.

- Some of this supply need can be met by low-cost energy efficiency (yellow bars) and nuclear uprates (light blue bars), both of which can be economic for market participants to pursue.

- Twelve GW of “replacement” capacity could come from new natural gas combined-cycle plants, the next least-cost option (grey bar). These plants emit about 60 percent less CO2 than coal plants and very few of the pollutants targeted by the EPA.

- At higher costs, existing combined-cycle facilities could increase their output to displace dirtier coal generation (red bars). In its recent study, The Future of Natural Gas, the Massachusetts Institute of Technology indicated that the nation’s fleet of natural gas combined-cycle plants currently runs at 41 percent of capacity, compared to a design capacity factor of 85 percent. The nation’s combined-cycle power plants clearly have the capability to make up some of the gap left by coal retirements.

- New wind, new nuclear, solar and clean coal all cost over $100 per MWh, exceedingly expensive compared to the other options. Federal subsidies shift a portion of the costs from electric ratepayers to taxpayers, but the subsidies do not change the overall economics of the technology. Nevertheless, we expect that significant amounts of new wind generation will be built in the future to meet state Renewable Portfolio Standards and potentially a federal standard as well.

The PJM Cost Curve demonstrates that many low-cost options exist to clean up PJM’s generation supply in the face of pending EPA regulations. Many can be achieved at a cost less than $80 per MWh. By comparison, the average all-in price at PJM’s main wholesale trading hub in 2008 was $87 per MWh (inflated to 2016 dollars). In other words, we believe that the PJM market participants can significantly reduce CO2, sulfur dioxide, nitrogen oxide and mercury emissions in coming years at a real cost of electricity that is materially lower than what consumers paid for power in 2008.

Simply put, the path to cleaner generation in PJM can be an affordable one.
Figure 4
PJM Supply Curve of GHG Abatement Opportunities

- Solar PV: $675 / $300 with incentives
- Clean Coal: $600 / $350 with incentives

Legend:
- Coal Retirements
- Energy Efficiency
- Nuclear Upgrades
- Coal-to-Gas Switch
- Solar Photovoltaic
- New Natural Gas Plant
- Wind Power
- New Nuclear Plant
- Clean Coal with CCS
- White line represents price after including effects of tax incentives or loan guarantees

Note: Assumes that EPA adopts a MACT standard to control emissions of hazardous air pollutants. Emissions reduction estimates for new generation capacity represent emissions reduced in the market as a result of the project; less emissions introduced due to the project.

Technology cost assumptions (in 2015 $/kW):
- Combined-cycle gas turbine: $1,300 - $1,700
- Wind: $0.00 - $1.00
- Nuclear: $5,000 - $6,000
- Clean coal with CCS: $5,700 - $6,200
- Solar photovoltaic: $5,000 - $6,000
One step further – the PJM Supply Curve

We also wanted to understand the PJM Cost Curve and anticipated EPA regulations in the context of our own Supply Curve, which integrates costs and our expectations for future power prices. As a result, we created a PJM Supply Curve of GHG Abatement Opportunities (see figure 4, page 10).

We found the results striking: in a world with EPA regulations, participants in PJM can abate approximately 60 million metric tons of CO2 emissions per year without the need for a carbon price. (Climate bills proposed in Congress recently had goals of reaching a national 17 percent reduction in CO2 emissions by 2020. PJM’s fair share of such a goal equates to about 80 million metric tons of CO2 per year.) This can be accomplished through energy efficiency, nuclear uprates, 13 GW of coal retirements, and 12 GW of new natural gas generation.

Piecing everything together, our analysis shows that 75 percent of the proposed congressional 2020 reduction goals can be met at (a) a cost lower than PJM prices in 2008 and (b) with no carbon price while (c) at the same time building new power plants and stimulating the economy. With a carbon price of just $20 per metric ton, the PJM Supply Curve shows that the region could fully meet a 17 percent CO2 emissions reduction goal by 2020. Even at that carbon price, the cost would remain below 2008 PJM prices. Existing combined-cycle gas plants running in favor of less-efficient coal plants is the option that requires a subsidy equivalent to a $20 carbon price and allows PJM to meet its share of the goal. As noted earlier, MIT’s *The Future of Natural Gas* suggests existing combined-cycle facilities can readily accommodate such a level of “re-dispatching.”

We understand that some may be discouraged by the position of wind, new nuclear, solar and clean coal at the far right end of all three curves presented in this report. All these options will have their place in the future of the country’s power generation mix. Further, we believe that the power industry should continue investing in these technologies. They will become more attractive as their costs decline and EPA regulations force the retirement of outdated coal capacity.

However, these options are not the primary answers for today – they are plainly too expensive relative to the alternatives, particularly in a fragile economy. And cost is no minor issue for Exelon or other industry players. We always are mindful that our customers desire affordable and reliable electricity. We know that they will more readily add clean electricity to this list if we can keep it affordable.

We take from our analysis that the power industry will move toward cleaner energy even in the absence of a carbon price in the near future. The key is to get started now. EPA must proceed with its mandate to create and enforce its regulations; old, dirty coal plants must retire; and market participants must respond by implementing the most cost-effective options first. These are all effective and necessary actions that the country must take as it awaits a price on carbon, a policy for which there is no long-term substitute.

We understand that some may be discouraged by the position of wind, new nuclear, solar and clean coal at the far right end of all three curves presented in this report. All these options will have their place in the future of the country’s power generation mix. Further, we believe that the power industry should continue investing in these technologies. They will become more attractive as their costs decline and EPA regulations force the retirement of outdated coal capacity.

However, these options are not the primary answers for today – they are plainly too expensive relative to the alternatives, particularly in a fragile economy. And cost is no minor issue for Exelon or other industry players. We always are mindful that our customers desire affordable and reliable electricity. We know that they will more readily add clean electricity to this list if we can keep it affordable.

We take from our analysis that the power industry will move toward cleaner energy even in the absence of a carbon price in the near future. The key is to get started now. EPA must proceed with its mandate to create and enforce its regulations; old, dirty coal plants must retire; and market participants must respond by implementing the most cost-effective options first. These are all effective and necessary actions that the country must take as it awaits a price on carbon, a policy for which there is no long-term substitute.
Progress and the path forward

With the Exelon Supply Curve guiding our actions, we see a clear path toward achieving the goal we set in 2008: to reduce, offset or displace 15.7 million metric tons of CO2 emissions per year by the year 2020. To date, we have achieved over 50 percent of this goal. This success has been accomplished through aggressive efforts across all three pillars of the Exelon 2020 strategy: greening our operations; helping customers reduce their GHG emissions; and offering more low-carbon electricity in the marketplace. The following pages include progress updates on our work and achievements.

We anticipate that the GHG abatement options we have already begun to pursue will allow us to meet and exceed the goal. We have already announced the planned retirement of our Eddystone and Cromby coal units. Our customer energy efficiency and renewable/alternative energy credit (REC/AEC) programs are ramping up quickly and will be significant contributors to meeting our goal. And between now and 2014, we will add more than 400 MW of new low-carbon electricity through the implementation of nuclear uprates that will abate more than 2 million metric tons of CO2 emissions per year.

We have developed a plan to implement an additional 900 MW worth of “extended” power uprates, but these projects will not be achieved until 2015 at the earliest given their long lead times and large capital investment requirements.

There will be ample opportunity to invest in new natural gas plants, but only when they are required to meet new demand. And we will evaluate the opportunity to participate in any carbon offset market created by future climate legislation because offsets hold the potential to minimize the cost of abating GHG emissions.
Figure 6
Meeting the goal – Exelon 2020 initiatives to reduce, offset or displace greenhouse gas emissions (million metric tons of CO2 per year)

- 15.7 Total
- 6.8 – Emissions reductions and offsets
- 0.9 – Customer energy efficiency programs and REC/AEC purchases
- 0.2 – Displacement–nuclear uprates

Wind and Other Renewables – 0.5
Nuclear Uprrates–MURs and LP Turbines – 2.5

- 1.7 – Coal retirements
- 0.2 – Additional internal GHG reductions
- 3.9 – Customer energy efficiency programs
- 2.9 – ComEd RECs and PECO AECs

Additional Options
- 4.5
- 0.4
- 1.4
- 1.5

Reduction, offset Exelon’s GHG emissions
Help our customers reduce their GHG emissions
Offer more low-carbon electricity in the marketplace
Greening our operations

We operate more than 125 commercial facilities across a service territory of more than 13,000 square miles. While Exelon consumes a lot of power in its internal operations, Exelon 2020 challenges us to use a lot less. The strategy is setting a new standard for low-emissions operations, proving every day that economic and environmental ambitions are compatible, sensible and feasible. In this section, we highlight a variety of our achievements, from cutting energy use in Exelon buildings to greening our supply chain and reducing emissions from our vehicle fleet.
Reducing energy consumption 25 percent in our facilities

Reducing Exelon’s own energy consumption without affecting productivity or adding unreasonable costs is no easy task. It requires discipline, coordination and innovative thinking. But through a company-wide commitment and sharp focus, we are achieving exactly that.

In 2008, Exelon set a goal to reduce energy consumption in its commercial facilities by 25 percent and in its power plants by 7 percent by the year 2012 (from a 2001 baseline). By the end of 2009, we had reduced energy use at our commercial facilities by 23.8 percent and auxiliary power use at our plants by 6.6 percent. These energy reductions correspond to a total GHG emissions reduction of nearly 145,000 metric tons.

Exelon Generation reduced its energy use by 27 percent during 2009, compared to a 2001 baseline, exceeding the goal. Notably, Exelon’s nuclear plants are expected to continue to reduce their internal energy use even though planned uprates increase the total amount of auxiliary power required. Exelon Nuclear is offsetting these increases by using energy more efficiently than ever before. Exelon Power exceeded its goals for reducing site auxiliary power usage in 2009 with the decrease in station runtime across the fleet.

Among the highlights of Exelon Generation’s Exelon 2020 work:

- An extensive building renovation at the Conowingo Visitor Center, including a 3.2 kilowatt solar array, earning it LEED-Existing Building Gold Certification.
- Replacement of a 45-year-old lighting system at the Fairless Hills Generating Station, resulting in an 80 percent energy savings per year.
- Extensive lighting replacements at power plants.
- Continuation of the work of the Kennett Square Environmental Council, which drove a number of initiatives including shuttle service between Philadelphia and Kennett Square, electric and water reduction best practices and recycling programs.

ComEd reduced building energy usage in 2009 by 29.5 percent compared to its 2001 baseline. This was achieved mostly through systems and process improvements, such as the installation of lighting and occupancy sensors at several facilities across its service territory. In 2010, ComEd expects to complete 12 energy conservation projects, which will help achieve its 2012 goal of 32 percent energy use reduction across its commercial facilities.

In the last year, PECO realized facilities savings of 12 percent, driven largely by its implementation of a multi-year LEED certification process for 10 of its largest buildings. Energy efficiency improvements at the Berwyn, Warminster and Phoenixville sites are saving 50 percent on electricity and gas usage and reducing water usage by 40 percent.
With the completion of energy efficiency measures at several locations, PECO has earned LEED-Existing Building Gold Certification at its Warminster Service Building and LEED-Existing Building Silver Certification at its Phoenixville Service Building and at the Berwyn Campus.

In 2010, PECO is pursuing energy efficiency improvements at Baldwin, Christian St., G & Luzerne and Plymouth Service Building sites in support of obtaining LEED-Existing Building certification by 2012. In addition, PECO also will complete lighting and HVAC upgrades at the Main Office Building by 2012.

Perhaps most visibly, 2009 brought a landmark change to the Philadelphia skyline with the replacement of PECO’s existing Crown Lights system with 2 million energy-efficient light-emitting diodes with color capability, resulting in a 40 percent energy savings.

In 2009 Exelon Business Services Company achieved an 18 percent reduction in energy usage compared to its 2001 baseline. BSC successfully renovated additional space in Exelon's Chicago headquarters, which is certified LEED-Commercial Interior Platinum. When added to Exelon's existing headquarters space, the company now has 247,000 square feet of contiguous LEED-Commercial Interior Platinum space, the largest in the world.

The new Conowingo Visitor Center has been LEED-Gold certified by the U.S. Green Building Council.

With the completion of energy efficiency measures at several locations, PECO has earned LEED-Existing Building Gold Certification at its Warminster Service Building and LEED-Existing Building Silver Certification at its Phoenixville Service Building and at the Berwyn Campus.

In 2010, PECO is pursuing energy efficiency improvements at Baldwin, Christian St., G & Luzerne and Plymouth Service Building sites in support of obtaining LEED-Existing Building certification by 2012. In addition, PECO also will complete lighting and HVAC upgrades at the Main Office Building by 2012.

Perhaps most visibly, 2009 brought a landmark change to the Philadelphia skyline with the replacement of PECO’s existing Crown Lights system with 2 million energy-efficient light-emitting diodes with color capability, resulting in a 40 percent energy savings.

In 2009 Exelon Business Services Company achieved an 18 percent reduction in energy usage compared to its 2001 baseline. BSC successfully renovated additional space in Exelon’s Chicago headquarters, which is certified LEED-Commercial Interior Platinum. When added to Exelon’s existing headquarters space, the company now has 247,000 square feet of contiguous LEED-Commercial Interior Platinum space, the largest in the world.

Exelon’s LEED-certified facilities

<table>
<thead>
<tr>
<th>Corporate Headquarters</th>
<th>LEED-Commercial Interior (CI) Platinum (247,000 square feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clinton Power Station administration building</td>
<td>LEED-New Construction (NC) Silver (79,500 square feet)</td>
</tr>
<tr>
<td>Conowingo Hydroelectric Plant Visitor Center</td>
<td>LEED-Existing Building (EB) Gold (4,864 square feet)</td>
</tr>
<tr>
<td>Fairless Hills Renewable Energy Education Center</td>
<td>LEED-CI Silver (3,970 square feet)</td>
</tr>
<tr>
<td>PECO West Chester service building</td>
<td>LEED-NC Silver (4,950 square feet)</td>
</tr>
<tr>
<td>PECO Berwyn Campus 1040 building</td>
<td>LEED-EB Silver*</td>
</tr>
<tr>
<td>PECO Berwyn Campus 1050 building</td>
<td>LEED-EB Silver*</td>
</tr>
<tr>
<td>PECO Berwyn Campus 1060 building</td>
<td>LEED-EB Silver*</td>
</tr>
<tr>
<td>PECO Phoenixville service building</td>
<td>LEED-EB Silver*</td>
</tr>
<tr>
<td>PECO Warminster service building</td>
<td>LEED-EB Gold*</td>
</tr>
</tbody>
</table>

* Berwyn/Phoenixville/Warminster five-building total: 320,000 square feet
Reducing emissions from our transmission and distribution infrastructure

Exelon continues to make emissions reductions in its transmission and distribution infrastructure. Most notable is the work being done to reduce sulfur hexafluoride (SF6) gas emissions across the business. SF6 gas is a highly effective insulator used in high-voltage equipment, but has a GHG impact 23,900 times greater than CO2. The electric power industry uses 75 to 80 percent of all SF6 produced worldwide, and leaks can occur due to aging equipment and during equipment maintenance and servicing.

Through March 2010, Exelon Power has reported zero emissions of SF6, hydrofluorocarbons / perfluorinated compounds refrigerant leakage or fire suppression system CO2 usage. ComEd released 3,531 pounds of SF6, beating its 2009 target by nearly half, and PECO released 8,298 pounds, beating its goal by approximately 40 percent. The SF6 emissions in 2009 are reflective of the downward trend in SF6 emissions over the past five years. In the last year, ComEd and PECO replaced a total of 12 circuit breakers that use SF6 and purchased four state-of-the-art leak detection cameras. Additionally, PECO has made important reductions in its methane emissions from its natural gas distribution system; methane gas has a global warming potential that is 21 times more potent than CO2.

Greening our supply chain

Exelon is working to reduce the environmental impacts of the materials and services we procure, and to encourage the environmental performance of our suppliers.

In 2009, Exelon developed environmental questions that are now included in sourcing requests. This allows Exelon to evaluate the environmental performance of its suppliers. In 2010, Exelon is developing a number of environmental standards to be incorporated in its business processes, including standards for transformers, wire and cable, wood poles and the vehicle fleet. In conjunction with the EPA, Exelon is conducting five Green Supplier Network reviews this year. The reviews assess sustainability opportunities in our suppliers’ manufacturing facilities.

As one of the founders of the Electric Utility Industry Sustainable Supply Chain Alliance (www.euissca.org), Exelon has become a national leader in supply chain-environmental management. Through the Alliance, Exelon has helped lead the development of industry standards for evaluating the environmental attributes of key materials and services as well as performance metrics for supplier companies.

Going forward, Exelon Business Services Company is supporting the development of the Alliance’s 2010 – 2012 strategic plan, facilitating the second annual Alliance supplier environmental survey and helping establish the Alliance’s GHG reduction goals.
Greening the supply chain also means reducing the impacts from the materials and services we procure. During 2009 Exelon recycled more than 4 million pounds of office waste, 380,000 pounds of technology waste and 22 million pounds of scrap metal, and recycled or reused more than 843,000 gallons of oil.

In Information Technology, we’ve replaced more than 4,700 monitors with more efficient models and our server virtualization process continued with more than 200 physical servers moved to the virtual platform.

Exelon’s Supply group has introduced eco-friendly products, including cleaning products and biodegradable trash bags, across all business units. Supply, in conjunction with ComEd, has also developed an innovative recycling process for transformer oil. The oil is stored in tanks, filtered to remove particulates and moisture, and then tested for acceptability before being used in other transformers. This process saved $115,000 in 2009 and allowed for the recycling of 40,000 gallons of oil.

Reducing emissions from our vehicle fleet

Exelon operates a fleet of more than 4,400 vehicles that log more than 40 million miles per year and in 2009 consumed the equivalent of 5.5 million gallons of fuel. So, an important part of greening our operations involves reducing GHG emissions from our trucks and other service vehicles.

In 2011, ComEd and PECO will deploy plug-in hybrid-electric (PHEV) trouble trucks and Chevrolet Volts through a partnership with the Electric Power Research Institute (EPRI) to upgrade their fleets and reduce fuel consumption. Backed by $45 million in federal stimulus funding, the program will help put more than 300 energy-efficient bucket trucks into use across the country. Through the use of stimulus grant money available to EPRI, ComEd will deploy 25 PHEV trucks and PECO will deploy 20 PHEV trucks. A separate study with EPRI will allow ComEd to evaluate 11 Chevrolet Volts and PECO to evaluate two. Both projects will include the use of advanced telemetry to collect data on power consumption, fuel usage and other performance metrics as part of the industry’s ongoing research into advanced batteries and charging infrastructure for electric vehicles.

PECO added four compressed natural gas (CNG) vehicles and five hybrid pickup trucks to its utility fleet in 2009. PECO’s alternative-fuel vehicle fleet consists of more than 47 hybrid vehicles, a prototype hybrid bucket truck, 16 natural gas vehicles and 651 biodiesel trucks. In total, alternative-fuel vehicles represent 55 percent of PECO’s total fleet of cars and trucks. As part of these initiatives, PECO now has six CNG refueling stations at its service buildings, all of which can be used by the public.

ComEd was awarded $4 million in federal economic stimulus funding under three grants to expand its use of alternative fuels and petroleum fuel reduction technologies, including the installation of
“Smart” electric vehicle charging infrastructure to help prepare the Chicagoland area for electric vehicles. In 2009, ComEd added 58 hybrids and PHEVs to its utility fleet, including eight hybrid bucket trucks and 10 Toyota Prius PHEVs. The company’s green vehicles number more than 2,100 and comprise 63 percent of its overall fleet.

ComEd is partnering with the City of Chicago under the U.S. Department of Energy’s Clean Cities Grant program to deploy a network of public and private vehicle smart-charging stations in the Chicago area, including two solar-powered stations. In addition, ComEd is participating in the Department of Energy’s Transportation Electrification grant program in partnership with EPRI to demonstrate the performance of PHEV bucket trucks in real-world working conditions.

ComEd also was awarded $253,000 from the Illinois Environmental Protection Agency to retrofit 37 of its large diesel vehicles with engine idle reduction technology in a pilot project that is expected to save about 6,000 gallons of biodiesel fuel per winter.

**Offsetting a portion of our own emissions**

Exelon continues to support The Field Museum’s efforts to conserve vast expanses of forests in the headwaters of the Amazon and to generate the highest quality carbon-offset credits from the Reduced Emissions from Deforestation and Forest Degradation pilot project in Peru’s Cordillera Azul National Park. The methodology to calculate the offsets is now undergoing validation.

The Field Museum uses widely respected protocols set by the Voluntary Carbon Standards and Climate, Community & Biodiversity Alliance, and with its partners has been able to use the volumes of data that they have gathered for the park since 2000 to estimate GHG emissions reductions. Conservative results suggest annual CO2 emissions reductions ranging from 2 million metric tons in 2009 to more than 5 million in 2018; the exact number will be verified once the methodology is validated. The Field Museum expects to be marketing verified carbon credits in 2011.

Exelon’s support of The Field Museum’s efforts to conserve vast expanses of forest in Peru’s Cordillera Azul National Park preserves natural habitats and helps reduce CO2 emissions.
Helping our customers and the communities we serve reduce their greenhouse gas emissions

With nearly 5.4 million customers, Exelon has an enormous responsibility and opportunity to help customers reduce their own greenhouse gas emissions, and is spending more than $400 million through 2011 on a range of innovative energy efficiency and demand response programs to do just that.

Our results include significant customer energy-use reductions achieved through our ComEd and PECO Smart Ideas℠ programs. The net result of these energy efficiency savings has helped avoid more than 220,000 metric tons of GHG emissions from the power plants that supply these retail customers. Beyond energy efficiency, ComEd and PECO have made enormous strides in the implementation of smart meters, which is the first piece of the broader smart grid vision.

PECO introduced “Ogres,” a multimedia advertising campaign that supports PECO’s Smart Ideas suite of energy efficiency programs.
Customer energy efficiency programs

Exelon’s energy efficiency programs place it in the top quartile among the nation’s utilities for customer energy savings. Over the next five years, spending on energy efficiency and demand response across the Exelon companies is anticipated to reach $290 million per year in northern Illinois and southeastern Pennsylvania, resulting in an estimated cumulative energy savings of 3.7 million MWh and a reduction in peak load of 388 MW.

ComEd has completed its second year of a three-year, $235 million energy efficiency program that targets residential and commercial energy savings. Its Smart Ideas flagship program is expected to produce lifetime electricity savings of more than 10 million MWh. In its second year of the Smart Ideas program, ComEd helped customers reduce their electricity consumption by more than 350,000 MWh through CFL bulb replacement, appliance recycling, air conditioning cycling programs and other initiatives. ComEd also has enrolled 11,255 customers in its residential real-time pricing program, and filed its next three-year customer energy efficiency plan on Oct. 1, 2010. Combined, ComEd’s energy efficiency and demand response programs have produced over 514,000 MWh of energy savings to date.

In 2009, PECO began its own Smart Ideas program. This comprehensive, $342 million energy efficiency program for residential and business customers is pursuing a goal to reduce overall electricity consumption by 3 percent and peak load by 4.5 percent by 2013. PECO’s Smart Ideas program has already helped customers reduce their electricity use by over 300,000 MWh. Since the official launch of the programs, more than 80,000 residential rebates have been processed, over 700 retail store locations have been provided with CFL bulbs and over 3.5 million bulbs have been sold through August 2010. In March 2010, PECO opened the region’s first appliance recycling center to recycle energy-guzzling refrigerators and freezers for PECO, PPL Electric Utilities and FirstEnergy customers. The facility will eventually serve about 80 percent of the state’s electric utility customers and create 40 new green jobs. Since the program launch, more than 10,000 refrigerators, freezers and room air conditioners have been recycled, representing over 13,000 MWh in energy savings. Business customers also have realized efficiency savings exceeding 30,000 MWh.

Investing in smart grid and smart meters

One of only six utilities to receive major stimulus funding, PECO was awarded a $200 million Smart Grid Investment Grant (SGIG) from the U.S. Department of Energy in late 2009. PECO has begun implementation of a smart grid/smart meter initiative, which includes installation of an advanced communications network, support systems and deployment of 600,000 smart meters to PECO customers scheduled for completion in 2013. The two-way communications network and advanced meters will equip customers with information and tools to better manage their energy use, thus creating greater opportunities for energy conservation and cost control.

Through the SGIG, PECO is working with Drexel University, Liberty Property Trust, the University of Pennsylvania and other partners to develop pilot projects that demonstrate customer-side applications of these new technologies.

Advanced metering infrastructure – the combination of communications network, technology support systems and smart meters – will enable PECO to improve customer service and increase reliability by obtaining real-time outage information and power quality data to accelerate restoration times.
ComEd has launched a one-year smart meter program and has already installed approximately 120,000 smart meters. This new technology will provide customers with daily usage information at ComEd.com/SmartTools to help them monitor energy use and manage costs. Customer service representatives can view actual usage data and answer questions about power status and billing without having to wait for a technician visit. As an added benefit, most smart meter customers also will receive periodic Home Energy Reports showing how their households are using electricity and providing energy saving ideas. In addition, ComEd is conducting an experimental Customer Application Program that will attempt to determine the benefits of various combinations of rates, enabling technology, customer education and customer experience.

ComEd is developing a Photovoltaic (PV) Pilot study in conjunction with the U.S. Department of Energy (DOE). If approved, the DOE will contribute nearly $5 million in federal stimulus funding for the three-year PV pilot that will study the customer benefits of rooftop solar electric systems and the impact they have on ComEd’s electric distribution system. This project will investigate customer electricity consumption impacts in conjunction with advanced pricing programs, such as hourly pricing and net metering, observe and evaluate the way consumers engage with technology and respond to energy pricing signals, and assess the attitude of consumers toward adopting new/emerging technologies. As part of the study, 100 homes from communities in the smart meter pilot area will receive solar photovoltaic systems. Each home also will receive leading-edge technologies that can help its occupants understand their energy usage behavior, including secure access to a website to monitor their energy usage, view the output of their solar panels and observe hourly electricity pricing information.

Expanding green product and service offerings

As part of Exelon 2020, we are expanding the range of green products and services offered to wholesale, retail and utility customers.

Wholesale and retail customers

Exelon Energy, the competitive retail subsidiary of Exelon, offers a suite of low-carbon products to commercial customers. In 2009, Exelon Energy introduced Emission-Free Energy Certificates (EFECs) as part of a pilot program that allows commercial and industrial customers to compare air pollution impacts from low-carbon generation sources to the standard blend of generation resources available in the region. In the past year, the program has sparked interest in EFECs as a competitive alternative to Renewable Energy Certificates in the voluntary marketplace. Exelon Energy recently had several pilot program customers request that EFECs be added to their existing energy agreements.
Utility customers
Exelon’s delivery companies continue to expand their green product and service offerings.

Included in the Exelon 2020 measure of GHG displacement are RECs procured by ComEd to meet its obligations in Illinois. Through this program, ComEd purchased more than 1.5 million MWh of RECs for the 2009-2010 program year. In 2010-2011, ComEd is projected to purchase nearly 1.9 million MWh of RECs. All together, these credits will help avoid more than 1.9 million metric tons of GHG emissions from fossil power plants.

PECO has signed 10-year agreements to purchase the equivalent of 6 MW, or 80,000 MWh, of solar RECs in support of Pennsylvania’s Alternative Energy Portfolio Standards. This is equivalent to the amount of energy needed to power nearly 1,000 homes for 10 years. These solar purchases are in addition to more than 450,000 MWh of wind and other RECs already purchased by PECO since 2008. PECO also completed its second of two RFPs for non-solar AECs, which combined resulted in the execution of five-year contracts to acquire a total of 452,000 MWh of AECs annually, making PECO the first Pennsylvania utility to buy and bank AECs.

The PECO WIND program supplied 166,000 MWh of electricity on an annualized basis to more than 34,000 customers in 2009. Products like PECO WIND enable customers to have control over the GHG emissions and other environmental attributes of the energy they buy.

Customer education and outreach
Exelon companies continue to implement a wide range of initiatives aimed at educating customers and reaching out to the communities we serve.

Both ComEd and PECO advertise to promote energy efficiency among their customer bases. ComEd engaged in the worldwide Earth Hour event to raise awareness about global warming and the benefits of energy efficiency. ComEd partnered with the World Wildlife Fund to promote Earth Hour and the resulting energy savings in the City of Chicago and ComEd’s northern Illinois service territory was estimated to be about 100 MWh.

Dedicated in May of 2009, the Fairless Hills Renewable Energy Education Center has hosted more than 2,000 students and members of Exelon Power’s business and community groups. The center features a variety of interactive displays to spark students’ interest in how electricity is created using landfill gas, the sun, wind and water. Students also are challenged to consider the cost of the various forms of electricity and to consider energy-saving opportunities. Exelon Power developed a traveling education program, including an energy carnival and information on renewable energy, that is being taken into schools in Pennsylvania, Maryland and Texas.

For the second year in a row, Exelon Nuclear is conducting “Gabby Green” programs in local schools around its 10 nuclear plant sites. The educational series is designed to teach young students about electricity, conservation and green energy.
Offering more low-carbon electricity

Exelon already offers more low-carbon electricity in the marketplace than any other power producer in the nation. More than 90 percent of Exelon’s generation output is low-carbon nuclear energy. Exelon’s nuclear fleet produces more than 130 million MWh of power annually – enough to power 11.5 million homes – with virtually no greenhouse gas emissions.

But we aim to do even more.

Offering more low-carbon electricity in the marketplace is the third pillar of the Exelon 2020 strategy and includes increasing the output of our nuclear fleet, investing in other low-emission energy generation and reducing the reliance on fossil generation. Since last year, Exelon has made important advances on all fronts. We acquired operating wind resources and wind project development capability, developed the nation’s largest urban solar installation, achieved new levels of nuclear generation capacity and have begun the process of retiring our coal-burning power plants, which will close in 2011 and 2012.

Exelon City Solar, the nation’s largest urban solar installation, is a 10-MW facility completed in 2010 on a former brownfield site in Chicago.
Increase investment in renewable power

In early 2010, Exelon completed the development of a 10-MW solar photovoltaic power plant on a brownfield site in an industrial corridor on the South Side of Chicago. Exelon City Solar is now the largest urban solar installation in the nation. Two hundred new construction jobs were created to install the 7,300 steel piers and more than 32,000 solar panels on the site. The plant uses GPS tracking devices to keep the solar panels moving to face the sun at all times. The clean energy generated by Exelon City Solar displaces more than 30 million pounds of GHG emissions per year. In developing the former industrial site, which had been vacant for over 30 years, Exelon removed pollutants and safety hazards and continues to beautify the property with an environmentally friendly design and sustainable landscaping, as well as a new visitor center.

Exelon recently agreed to acquire John Deere Renewables, which would add an operating portfolio of 735 MW of clean, renewable wind power projects to the company’s mix of generation assets. The 36 projects are located in eight states and provide enough capacity to power 160,000 to 220,000 households. The transaction also includes the opportunity to pursue the development of 1,468 MW of new wind projects, including 230 MW in advanced stages of development. Exelon expects to close the transaction in the fourth quarter of 2010.

Exelon Power has filed Notices of Intent and Pre-Application Documents with the Federal Energy Regulatory Commission (FERC) to relicense Conowingo, a run-of-the-river hydro facility, and Muddy Run, a pumped storage facility, on the Susquehanna River in Maryland and Pennsylvania, respectively, extending the life of these low-carbon generating facilities for another 40 years.

Reduce emissions from fossil generation

About 93 percent of our direct GHG emissions are attributed to our fossil power plant operations. Because of reduced demand, in 2009 our fossil plants produced 4.2 percent less electricity compared to 2008. This resulted in a total annual reduction of more than 5.8 million metric tons compared to the 2001 baseline.

Exelon Power has worked with PJM Interconnection on its plans to permanently retire three coal-fired units: Unit 1 at Cromby Generating Station and Unit 1 at Eddystone Generating Station will retire effective May 31, 2011, and Eddystone Unit 2 will retire effective June 1, 2012. Additionally, the gas- and oil-fired Cromby Unit 2 will retire effective Dec. 31, 2011, and Cromby Station will close entirely at that time. Following these retirements, Eddystone Station will remain in service, operating six oil/gas units capable of generating 820 MW.

In February 2010, Exelon announced its intent to join the FutureGen Alliance, Inc. (the Alliance), a public-private partnership between the U.S. Department of Energy and leading domestic and international companies. The Department of Energy recently announced a revised plan for the FutureGen project, called “FutureGen 2.0,” that consists of two parts. One part will be the repowering of an existing power plant with oxycombustion technology to capture 90 percent of the plant’s CO2 emissions. The second part, to be undertaken by the Alliance, will be the development of a regional CO2 storage hub that would transport captured CO2 and permanently store it in an underground saline formation at a site to be selected in Illinois. The project represents an important opportunity to advance clean coal technologies.
Expand nuclear generation

Since 2008, Exelon has added more than 100 MW in new nuclear generation, part of a series of planned capacity expansions across the existing nuclear fleet through 2017 that could create between 1,300 and 1,500 MW of additional generation capacity. Such capacity would be the equivalent output of a new advanced nuclear reactor, but comes to market faster and with less cost. Uprates improve the efficiency and increase electricity output of a nuclear generating unit through enhancements and upgrades to plant equipment. The projects take advantage of new production and measurement technologies, new materials and learning from a half-century of nuclear power operations.

Currently, uprate projects are underway at Exelon’s Braidwood, Byron, Dresden, LaSalle and Quad Cities plants in Illinois and at the Limerick and Peach Bottom nuclear stations in Pennsylvania. Exelon Nuclear is projected to add more than 75 MW in 2010 through uprates and megawatt recovery projects as part of its long-term commitment to uprate nine Exelon Nuclear plants. In total, 1,500 nuclear-generated megawatts over the next several years would displace 8 million metric tons of CO2 emissions annually and help Exelon more than exceed our 2020 goal.

Two Exelon nuclear stations – Oyster Creek and Three Mile Island Unit 1 – obtained license renewals in 2009 that will allow them to continue to generate emission-free electricity for another 20 years.

Exelon Nuclear Texas Holdings LLC, a wholly-owned subsidiary of Exelon Generation, filed an early site permit application with the Nuclear Regulatory Commission for an 11,500-acre site in Victoria County, Texas. While Exelon is not actively pursuing new plant development, the early site permit would effectively reserve the property for new nuclear construction for up to 20 years. The application accommodates a variety of possible future plant designs, allowing for flexibility in selecting a reactor technology later as part of a future full license application.

Exelon Nuclear replaced all three low-pressure turbines of Quad Cities Unit 2 during a planned refueling and maintenance outage in March 2010, increasing output by 40 MW. Following the completion of power uprates on both units at Quad Cities in 2011, the station will generate enough new electricity to power an additional 64,000 homes.
Exelon 2020 greenhouse gas abatement goal
The greenhouse gas (GHG) abatement goal for Exelon 2020 is an absolute annual emissions goal of 15.7 million metric tons of CO2-equivalent that corresponds to our 2001 direct and indirect GHG emissions, as determined under the U.S. EPA’s Climate Leaders Program. The expanded scope of Exelon 2020 is more comprehensive than our EPA Climate Leaders GHG inventory. Our reported Exelon 2020 progress accounts for direct and indirect GHG emission reductions and offsets, and this year’s report newly includes project-based emission reductions, customer GHG abatement and new low-carbon generation displacement.

Direct and indirect emission reductions
Reductions in GHG emissions from our operations are relative to our 2001 base-year emissions. These include stationary and mobile combustion of fossil fuels, fugitive emissions of GHGs (e.g., methane, SF6, CO2, and hydrofluorocarbons) and indirect emissions associated with the purchase of electricity from external sources. Accounting for these reductions is performed in accordance with the EPA Climate Leaders GHG accounting framework.

Offsets
Exelon procures and retires Renewable Energy Credits (RECs) as part of the electricity supply for certain facilities, including some that have been LEED certified. These offsets have been included in our annual Climate Leaders reporting. The factors (pounds/MWh) used for estimating the avoided fossil generation GHG emissions associated with RECs are based on the eGRID Subregion Emission Rates for the average PJM emission rates, as referenced in the U.S. EPA Climate Leaders Greenhouse Gas Inventory Protocol, ”Indirect Emissions from Purchases/Sales of Electricity and Steam,” October 2004, Appendix B: 1,243.2 pounds CO2e per MWh in Illinois and 1,103.08 pounds CO2e per MWh in Pennsylvania. These factors have been held constant for the period of our Climate Leaders commitment to allow for year-to-year review of progress and may be revised for future year reporting.

Project-based reductions
Reductions related to changes in operations that are outside of the scope of Exelon’s U.S. EPA Climate Leaders conformance GHG inventory for direct and indirect emissions, such as material recycling and sequestration projects, are included as project-based reductions in Exelon 2020 performance. Including these activities in our Exelon 2020 performance enables us to account for their real contributions to global GHG emission reductions and promote the value of engaging in these activities. The U.S. EPA Waste Reduction Model was used as the basis for estimating our commercial facility material recycling and investment recovery activities. GHG emission reductions attributed to the recycling of coal combustion products are based on the methodology developed by the Utility Solid Waste Activities Group report, ”Estimating GHG Savings from Use of Coal Combustion Products: Methodology and Results for 2000-2001,” that is available at: http://www.uswag.org/ccpuse.pdf

A methodology for waste-oil recycling was developed with our oil recycling vendor, which recycles this material for reuse, thereby avoiding the incremental emissions associated with producing virgin product for our use. Our GHG reduction estimates for oil recycling and reuse are based on 23 pounds CO2e per gallon for transformer oil.

Customer abatement
Through the ComEd and PECO Smart Ideas programs, Exelon is helping its customers reduce their electricity use through energy efficiency measures, in conformance with Illinois and Pennsylvania state mandated requirements. Exelon also is procuring and retiring RECs for retail customer supply, in compliance with state mandated renewable supply requirements. The customer energy efficiency estimates for GHG abatement are based on the MWh reported to the Illinois Commerce Commission by ComEd and to the Pennsylvania Public Utility Commission by PECO. The factors (pounds/MWh) used for estimating the avoided fossil generation GHG emissions for both energy efficiency and REC purchases are based on the same factors as those used for REC offsets, namely: 1,243.2 pounds CO2e per MWh in Illinois and 1,103.08 pounds CO2e per MWh in Pennsylvania. These factors have been held constant for the period of our Climate Leaders commitment to allow for year-to-year review of progress and may be revised for future year reporting.

Low-carbon generation displacement
Through the addition of new low-carbon capacity from uprates at existing nuclear plants, Exelon is able to displace marginal, more carbon-intensive fossil generation, thereby reducing the GHG emissions from generation in its operating regions. PJM Interconnection has developed marginal CO2 emissions factors for 2009, based on actual marginal operating plant emissions: http://www.pjm.com/documents/~/media/documents/reports/co2-emissions-report.ashx. Utilizing the average marginal emissions rates for on-peak (1,831 pounds/MWh) and off-peak (1,823 pounds per MWh) periods, the displaced CO2 emissions are estimated for the generation produced from Exelon’s equity share of the nuclear capacity uprates.
This report was printed with low-VOC emitting UV inks on Mohawk Options Smooth True White paper, which is made with 30% post-consumer recycled fiber. Mohawk Fine Papers purchases renewable energy certificates, certified by Green-e, that are equivalent to 100% of the electricity used in its operations. This paper is also certified by Green Seal and by SmartWood for Forest Stewardship Council (FSC) Standards, which promote environmentally appropriate, socially beneficial and economically viable management of the world’s forests. In addition, the thermal energy emissions created in manufacturing of Mohawk Options Smooth True White paper have been entirely offset with Verified Emissions Reduction credits, making this paper 100% carbon neutral. Mohawk has provided the calculations below based on the use of 4,500 pounds of Mohawk Options Smooth True White paper.

The savings derived from using this paper in lieu of virgin fiber paper is equivalent to:

- 13 trees preserved for the future
- 37 lbs. water-borne waste not created
- 5,505 gallons wastewater flow saved
- 609 lbs. solid waste not generated
- 1,199 lbs. net greenhouse gases prevented
- 9,180,000 BTUs energy not consumed

The additional savings derived from choosing a paper manufactured using wind power and carbon offsets:

- 2,030 lbs. GHG emissions not generated
- 2 barrels fuel oil unused
- 2,009 miles not driven in an average car
- 138 trees planted

This amount of wind-generated electricity is equivalent to:

- 9,180,000 BTUs

Forward-Looking Statements This Current Report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements include those discussed herein as well as those discussed in (i) Exelon’s 2009 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operation and (c) ITEM 8. Financial Statements and Supplementary Data: Note 18; (ii) Exelon’s Second Quarter 2010 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part I, Financial Information, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 12; and (g) other factors discussed in filings with the Securities and Exchange Commission by the Registrant. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. The Registrants do not undertake any obligation to publicly release any revision to their forward-looking statements to reflect events or circumstances after the date of this Current Report.

©2010 Exelon Corporation
Challenges for Integration of Policy Goals
Into the Northeast Regional Markets
Balancing Federal, State and Local Policies

Debra L. Raggio

Energy Bar Association
Northeast Chapter Annual Meeting
June 7, 2011
Keeping The Balance

• Federal, state and local policies should “let the markets work”
  • Market rules must be competitive
  • If markets aren’t competitive, the solution is to fix the rules
  • Artificially suppressing prices is not fixing the market rules.

• State policies may not interfere with interstate markets
  • States have authority over commerce within the state borders
  • FERC has authority over interstate electricity markets

• Federal policies should not conflict with one another
  • A company should not be forced to violate one law because it is complying with another

• Local policies should not try to resolve global or, at the very least, national issues
The Markets Are “Working”
e.g. PJM

- Enables resource (generation/ancillary services) sharing
- Providing market prices below what is needed to bring new generation
- Brought significant investment in capacity
- Developed robust demand response
- Lowered installed capacity needs
- Brought investment in renewables
State Policy May Not Interfere With Interstate Markets

- If market prices are not signaling a shortage of generation then you don’t need new generation.

- States are not prevented from building generation within their borders.

- States may *not* try to artificially suppress interstate market prices—manipulation is *not* allowed (up or down).

- If building generation requires entering into an above-market contract, ratepayers will pay the unnecessary costs.
Conflict of Federal Laws

• Generator needs to run for reliability under Federal Power Act
  – Reliability determination made by RTO/ISO
  – DOE authority under 202(c) of the Federal Power Act (FPA)
  – State Commission petition to FERC under FPA Section 207

• Generator must be in environmental compliance under the Clean Air Act
  – Must be in compliance with permit limits
  – States require compliance with NAAQS
  – Enforcement action and/or private citizen action liability

• When ordered to run and there is a resulting environmental violation – who trumps?
  – Case of first impression
  – Arguable that Clean Air Act trumps under statutory construction
  – Need to amend the FPA or the CAA to avoid conflict
The Challenges Moving Forward

• Balancing environmental limitations, reliability and various forms of generation supply will be a challenge
  – Policies must ensure reliability during this challenge
  – Policies must allow prices to respond to the challenge
  – Proper market signals will incent capital expenditure to meet the challenge
• Renewables and demand response present a challenge
  – Policies must ensure that these forms of energy actually show up when needed
  – Policies must recognize that incentives must eventually be phased out
• The focus must be on the facts and not the rhetoric
Exhibit A
16 U.S.C. 824a(c).

(c) Temporary connection and exchange of facilities during emergency

During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.
16 U.S.C. 824f. Ordering furnishing of adequate service

Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any inter-state service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: Provided, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.
Exhibit B
United States of America
Department of Energy

District of Columbia Public Service Commission ) Docket No. EO-05-01

Order No. 202-05-3

I. Summary

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will meet the emergency and serve the public interest. Therefore, Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), are hereby ordered to generate electricity at their Potomac River Generating Station (the “Plant”) pursuant to the terms of this order.

II. Procedural History

On August 19, 2005, Mirant submitted to the Virginia Department of Environmental Quality (DEQ) a computerized emissions modeling study Mirant had conducted of its Plant that indicated that emissions from the Plant caused or contributed to significant localized exceedances of the National Ambient Air Quality Standards (NAAQS).\(^1\) Also on August 19, 2005, DEQ issued a letter to Mirant which requested “that Mirant immediately undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shut down of the facility.” (emphasis in original). The letter asked Mirant to provide DEQ with a summary of the actions taken and the progress toward eliminating NAAQS exceedances by August 24, 2005. At midnight on August 21, 2005, Mirant reduced production of all units at the Plant to their minimum load, and at midnight on August 24, 2005, Mirant shut down all five of the generating units at the Plant.

On August 24, 2005, the District of Columbia Public Service Commission (DCPSC) filed an Emergency Petition and Complaint with both the United States Department of Energy (DOE or Department) and the Federal Energy Regulatory Commission (FERC or Commission) pursuant to the FPA. The DCPSC requested the Secretary of Energy to find that an emergency exists under section 202(c) of the FPA and to issue an order directing Mirant to continue

\(^1\) The Clean Air Act, 42 U.S.C. § 7401 \textit{et seq.}, authorizes the United States Environmental Protection Agency (EPA) to establish NAAQS, 42 U.S.C. §§ 7408-7409, and states that it is the responsibility of the states and local governments for assuring that they are attained, 42 U.S.C. §§ 7401(a)(3) and 7416.
operation of the Plant. The basis for the petition was that the shutdown of the Plant "...will have a drastic and potentially immediate effect on the electric reliability in the greater Washington, D.C., area and could expose hundreds of thousands of consumers, agencies of the Federal Government and critical federal infrastructure to curtailments of electric service, load shedding and, potentially, blackouts." The DCPSC requested that the Commission issue a similar order under sections 207 and 309 of the FPA. Numerous parties filed interventions and comments in response to DCPSC's emergency petition, as well as subsequent comments and responses. Further, both FERC and DOE issued information requests to Mirant, the Potomac Electric Power Company (PEPCO), the company responsible for supplying electricity to retail customers in the District of Columbia, and PJM Interconnection, LLC (PJM), the grid operator responsible for the administration of the bulk power grid and electricity market in the region. In addition to the DCPSC petition proceedings, DOE has hosted and participated in numerous conference calls and meetings to gather information on the shutdown of the Plant and its effect on the reliability of D.C.'s electricity system.

III. Background

The coal-fired Mirant Plant, which began operation in 1949, is located in Alexandria, Virginia, and is capable of producing 482 megawatts of electricity primarily for delivery to Washington, D.C. The Plant consists of five generating units, two of which are cycling units that range in output from 35 MW to 88 MW, and three of which are baseload units that range in output from 35 MW to 102 MW. It is one of only three sources of electricity that serve the central business district of the District of Columbia, many federal institutions, the Georgetown area in D.C., as well as other portions of Northwest, D.C., and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Water Treatment Plant, the largest wastewater

---

2 Several of these filings were only made in the FERC docket and not in DOE's docket. Even though a number of filers did not submit their comments in the DOE docket, the Department has, in the interest of rendering an appropriate and fully informed determination, reviewed all the filings in the FERC docket for any pertinent facts that will assist the Department in making its decision. Also, to the extent the filings contained analysis or legal arguments pertaining to the Department's 202(c) authority, they have been considered in the Department's decision making process.

3 The data submitted contained Critical Energy Infrastructure Information and was submitted in both confidential and redacted versions, as defined in FERC's rules at 18 C.F.R. § 388.13. All information contained in this order is from public filings in the DOE and FERC dockets.

4 The Administrative Procedure Act's prohibitions on ex parte communications in an adjudicatory proceeding, 5 U.S.C. § 557(d)(1), do not apply to DOE's 202(c) proceedings, because section 202(c) explicitly authorizes the Department to issue a 202(c) order "either upon its own motion or upon complaint, with or without notice, hearing, or report..." 16 U.S.C. § 824a(c).
treatment plant in the world. The other two sources are two 230 kV lines that deliver electricity from other generating sources in the regional electric grid operated by PJM. Although there are other generating units in close physical proximity to the Central D.C. area, (e.g., the Benning Road and Buzzard Point generating facilities, which are dual-fueled oil and natural gas generating power plants, owned by PEPCO) there are no transmission lines that would allow delivery of power from these other units to reach the Central D.C. area. With regard to the sources of power that serve the Central D.C. area, PEPCO owns and operates the transmission lines, and PJM determines electricity demand.

Although Mirant shut down all of the Plant’s generating units on August 24, 2005, it has since restarted unit number one which, the Department understands, is currently operating. Mirant is operating the unit on an 8/8/8 basis --- that is, in any given twenty-four hour period, the unit runs for eight hours at its maximum level of 88 MW, eight hours at its minimum level of 35 MW, and has eight hours when it does not run. DOE has been informed that both EPA and DEQ acknowledge that the operation of this unit in this manner does not result in any NAAQS exceedances. In addition, DOE understands that Mirant is taking other steps to increase production at the Plant in a manner which will be acceptable to DEQ and EPA.

PEPCO has applied to the DCPSC to construct two new 230 kV lines that would supply electricity to the Central D.C. area. In the same application, PEPCO has proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. PEPCO proposes having the two 69 kV lines installed by the summer 2006 peak season, and the two 230 kV lines installed in 18 to 24 months. The two existing 230 kV lines that supply the Central D.C. area would need to be temporarily taken out of service sequentially in order to connect the new lines to the Central D.C. area. Once completed, these lines apparently would provide a high level of electric reliability in the Central D.C. area, even in the absence of production from the Plant.

IV. Discussion

A. Reliability Issues

The Department has conducted an independent analysis of the electricity reliability situation in the Central D.C. area and has analyzed the Plant’s role in ensuring a sufficiently reliable supply of electricity to that area. DOE’s analysis was conducted by the Department’s Oak Ridge National Laboratory. Under North American Electric Reliability Council standards, at a minimum, the power system must carry at least enough contingency reserves of electricity to cover the most severe single contingency. The standards require that an area’s system always be operated with sufficient reserves to compensate for the sudden failure of the area’s most important single generator or transmission line.

---

5 For purposes of this order, the area supplied with electricity by these three sources will be referred to as the “Central D.C. area,” and the retail customers in this area will be referred to as the “Central D.C. area customers.”
Based on the fact that the Central D.C. area has only three sources of supply, the Plant and the two 230 kV transmission lines, the Department’s analysis concludes that in order to maintain a minimally reliable electric power system, the Plant must be available to run when one of the 230 kV lines is out of service, because if the remaining line failed there would be no other source of electricity to serve the Central D.C. area load. In addition, the analysis concludes that if one of the 230 kV lines failed unexpectedly, enough generation must be started as rapidly as possible so as to be able to serve all of the Central D.C. area load as a contingency reserve in the event the other line were to fail. The analysis also indicates that the Plant should be operated in such a way as to minimize the amount of time needed to bring it into production.

PEPCO has asserted that:

Absent the generating capacity of the Plant, if the two 230 kV transmission circuits into the [Central D.C. area] fail, there will be a blackout in much of the District of Columbia until the circuits are repaired or the Plant’s generators are restarted and can operate at a level that matches load. All electric customers in Georgetown, Foggy Bottom and major portions of downtown Washington will be affected. The affected customers will also include Blue Plains wastewater treatment plant. It is PEPCO’s understanding that within 24 hours of the loss of electric supply, Blue Plains will have no option but to release untreated sewage directly into the Potomac River, which would result in a significant adverse impact to human health, aquatic wildlife and other environmental resources. Affected customers will also include numerous hospitals, schools, universities, commercial buildings, and residential customers. Importantly, numerous federal facilities will lose power, including those critical to the security, safety, and welfare of the whole country, such as the FBI, the Justice Department, the State Department, the Federal Emergency Management Agency, the Department of the Interior, and the Department of Energy to name but a few. 6

No commenter has disputed these statements by PEPCO, and they have been generally corroborated by DOE’s own independent analysis; therefore, DOE will accept them as correct statements of fact. Further, the 230 kV lines do go out of service on occasion; since 2000, there have been 34 one-line outages for maintenance, and seven occasions where one of the lines has tripped unexpectedly. DOE has been informed that, prior to 2000, there were two occasions when both of the lines failed simultaneously.

B. Environmental Issues

Some commenters have asserted that the renewed operation of the Plant would result in NAAQS exceedances and a violation of the Clean Air Act, and that DOE could not issue a 202(c) order which would contravene the Clean Air Act (42 U.S.C. §§ 7401-7626). In response to this assertion, DCPSC, PEPCO and PJM contend that there were no actual monitored

---

6 See Potomac Electric Power Company’s Leave to Answer and Answer to Comments, FERC Docket No. EL05-145-000 at pages 2 & 3 (September 9, 2005).
exceedances of the NAAQS at the Plant during operation, and that operation of the plant at full power does not exceed the emissions limits contained in the Plant’s operating permit and therefore the operation of the Plant pursuant to a DOE order would not violate the Clean Air Act. EPA has shared information with DOE regarding NAAQS modeled results and other environmental issues at the Plant. In response to the environmental concerns raised, this order seeks to minimize, to the extent reasonable, any adverse environmental impacts. Should EPA issue a compliance order directed to operation of the Plant, DOE will consider whether and how this order should be met. DOE cannot issue an order without complying with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 et seq. Responders to that assertion stated that NEPA review requirements do not apply because any order would merely require the Plant to operate in the manner and at the level it has historically operated, and thus is not a “major federal action” triggering NEPA. In addition, responders assert that “...the emergency nature of the relief sought in this case permits the [the Secretary] to act without conducting a NEPA analysis, even if it were required.” DOE has determined that the emergency circumstances here make it necessary to take action without performing a NEPA analysis. Indeed, in order for an order under FPA section 202(c) to be issued at all, the Secretary of Energy must determine that an emergency exists, and I have made that determination here. DOE has consulted with CEQ about alternative arrangements pursuant to 40 C.F.R. § 1506.11.

C. Other Issues

Commenters opposed to the issuance of a FPA section 202(c) order cited Richmond Power & Light v. FERC, 574 F. 2d 610 (D.C. Cir. 1978) as imposing a limit on the Secretary’s authority to make an emergency finding under section 202(c). In Richmond, the New England Power Pool (NEPOOL) petitioned the Federal Power Commission (the Secretary’s predecessor in exercising section 202(c) authority) for an order pursuant to FPA section 202(c) to have utilities east of the Mississippi River with excess electric generating capacity supply NEPOOL with that excess capacity. The request was based on fears of an oil shortage due to the 1973 Arab oil embargo. The Commission responded by holding a conference and a series of meetings which resulted in an agreement among the purchasing, transmitting and supplying utilities and participating state regulatory commissions. As a result of the agreement, NEPOOL moved to withdraw its petition, which the Commission allowed. Richmond Power & Light Company challenged the decision to allow the withdrawal and the court found that the Commission did not abuse its discretion in declining to issue an order under section 202(c), but rather settling on the temporary-voluntary agreement program reached by the interested parties. Instead of limiting its...
reach, *Richmond* underscores the discretionary nature of the Secretary’s authority under section 202(c).\(^8\)

Another case asserted to limit the Secretary’s authority to issue an order under section 202(c) was *National Fuel Gas Supply v. FERC*, 909 F2d 1519 (D.C. Cir. 1990). In that case, National Fuel applied under section 7 of the Natural Gas Act (NGA), 15 U.S.C. § 717 et seq., for a certificate of public convenience and necessity to allow it to make interruptible sales of natural gas. The Commission imposed a condition that National Fuel accept a blanket transportation certificate to provide open access transportation. The court ruled that the Commission was improperly using a NGA section 7 certificate condition in place of an individual or generic proceeding under section 5 of the NGA. The Department does not see the relevance of *National Fuel* here. I am using section 202(c) of the FPA for precisely the type of situation contemplated by section 202(c) of the FPA.

V. Decision

Section 202(c) of the FPA vests in the Secretary of Energy the authority to issue an order when “an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes....” 16 U.S.C. § 824a(c). DOE’s regulations acknowledge that “[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated by these regulations.” 10 C.F.R. § 205.371.

I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation’s Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

---

\(^8\) The facts in *Richmond* and in the current situation are very different. *Richmond* dealt with a wide regional or even national energy shortage situation, while we are considering electricity reliability in a discrete geographic area. The facts here more closely resemble those considered by the Federal Power Commission in *City of Cleveland, Ohio v. Cleveland Electric Illuminating Company*, 47 FPC 747 (1972). In that case, the City of Cleveland petitioned the Commission pursuant to section 202(c) to order an interconnection with Cleveland Electric Illuminating Company to provide services during shortages caused by outages of the City of Cleveland’s generating facilities, or delays getting generation on line. The Commission found that the City of Cleveland had an emergency due to periodic shortages of generating facilities caused by outages and ordered the establishment of a 69kV temporary emergency interconnection between the electric systems of the City and Cleveland Electric Illuminating. Similarly, here DOE is ordering the Plant to provide electricity in certain limited situations.
More specifically, if the Mirant plant is not available to generate electricity and one of the two transmission lines serving the Central D.C. area goes out of service, the Central D.C. area would be served by only one transmission line. Should that remaining line fail for any reason, a blackout would occur in the Central D.C. area, potentially for an extended period of time. In fact, if one or both of the transmission lines could not be brought back into service immediately and the only source of energy for the Central D.C. area was the Mirant Plant, in the absence of today's order it would take several hours at a minimum to bring the Plant into full operation.

The outage of one of these two lines is not merely a theoretical possibility. On Friday, December 16, 2005, PJM informed DOE that on the previous night, "one of the two circuits critical to providing service to the District tripped. Continued [electric] service to certain load within the District was at that time entirely dependent on the remaining circuit." As a result, PJM requested dispatch of a second generating unit at the Plant, but Mirant refused to do so. PJM informed DOE that "service was not interrupted because load was low and the remaining circuit performed without incident." Fortunately, full service to the line that had tripped was restored by the morning of December 16. Nonetheless, there can be no assurance that the Central D.C. area will be so lucky next time, either with respect to the timing of the event, the operation of the second transmission line, or the ability to bring the first transmission line back into service.

Furthermore, it is periodically necessary for an outage to occur on one of the transmission lines because of the need to perform maintenance. In fact, maintenance is scheduled on one of the lines in the next few weeks. Thus, as occurred on the night of December 15, 2005 and as will certainly occur again in the future, if the Mirant Plant is not made operational Central D.C. will find itself relying solely on one transmission line. The duration of an outage can range from up to several days (for maintenance) or even longer (up to weeks) if the outage of a line is due to a major equipment failure. Throughout such a period, if the Plant is not fully operational a blackout in Central D.C. is only one step away, i.e., if an event should occur that causes the second line to fail. Such a blackout could last for hours or days.

I recognize that, if past experience is any guide, the simultaneous failure or outage of both transmission lines serving the Central D.C. area is not a high probability. While this event has occurred in the past, it has not happened often. Moreover, the recent tripping of one circuit does not in itself dictate the existence of an emergency justifying issuance of a 202(c) order.

The facilities and functions that would be adversely affected by an extended blackout in this instance, however, is an important consideration. The Central D.C. area includes offices, facilities and operations involved in all three branches of government, and that are critically important to the Nation's national security, law enforcement and regulatory functions. The Central D.C. area also includes hundreds of thousands of residents and workers, and all manner of public safety and protection facilities, including hospitals, police, and fire facilities. Moreover, DOE has been informed that within 24 hours of a blackout in the Central D.C. area, untreated sewage from the Blue Plains Wastewater Treatment plant would be discharged into the Potomac River.
Finally, it is noteworthy that a blackout in the Central D.C. area not only would affect critically important facilities and operations, it could last for an extended period. Depending on the reason for the outage of the transmission lines, the lack of service on those lines accompanied by the lack of generation by the Plant could result in a large portion of the District of Columbia being without electricity for a period that could last hours or days. At the very least, if the two transmission lines were made unavailable with no advance notice and the only source of electricity for the Central D.C. area was the Mirant plant, in the absence of today's order DOE understands it would take at least 28 hours, and likely longer, to bring the Plant into full operation, during which time all or a substantial part of the Central D.C. area would be without electric power. The results would be hardship and physical risk to hundreds of thousands of persons from loss of heat, elevator outages, medical equipment failure and numerous other causes. In addition, critical portions of the nation's government would also be severely impacted, with resulting adverse effects on a national scale.

Of course, the fact that the Department did not act immediately on the DCPCS petition does not argue against my finding that an emergency currently exists. After the petition was filed, DOE took several weeks to gather the relevant information, consider the facts, talk with environmental regulatory authorities, and develop an order that balanced the appropriate considerations. As explained in the text of this order, the current facts fully justify my finding that an emergency exists and that this order will meet that emergency. There certainly is nothing in the Federal Power Act that requires me to wait until a blackout actually has occurred, lives are put in jeopardy, and a significant disruption of National government functions already has happened before exercising my section 202(c) authority.

Accordingly, and based on all of the facts and circumstances, I find that an emergency exists justifying the issuance of this order under Federal Power Act section 202(c).

After finding the existence of an emergency, DOE has the authority, "either upon its own motion or upon complaint, with or without notice, hearing, or report, to order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). The statute gives the Secretary of Energy broad discretion to fashion the terms of an order that will, in the Secretary's judgment, "best meet the emergency and serve the public interest." Based on the circumstances described above in this order, I hereby direct Mirant to generate electricity at the Plant pursuant to the terms of this order.

While I am issuing this order to help ensure a reliable supply of electric energy to the Central D.C. area, I am cognizant of the concerns that have been expressed concerning the potential adverse environmental consequences of operating the Plant, and of the national interest in attainment of the NAAQS that have been established under the Clean Air Act. Ordering action that may result in even local exceedances of the NAAQS is not a step to be taken lightly. However, it would not be reasonable for the Department of Energy to stand by and take no positive action on the DCPCS petition, even though the Central D.C. area is in danger of an extended blackout and the Department and private parties have available to them the legal and operational tools to prevent such a blackout from occurring. In this order, I have sought to harmonize those interests to the extent reasonable and feasible by ordering Mirant to operate in a
manner that provides reasonable electric reliability, but that also minimizes any adverse environmental consequences from operation of the Plant.

DOE expects that the DCPSC, having sought an emergency order, will take such actions as are within its authority to provide adequate and reliable electric service for the Central D.C. area including, for example, expediting approval of PEPCO transmission system upgrades and instituting demand response programs.\(^9\) Indeed, DOE views this order not as a permanent solution to the Central D.C. area’s reliability issues, but rather as a bridge between the current untenable situation and a more permanent solution that must be crafted by appropriate parties, including the DCPCS, FERC, environmental regulatory authorities, and relevant private sector parties. This permanent solution may include the installation of the new transmission lines discussed above, the installation of new pollution control equipment at the Mirant Plant, or other means.

As explained above, in the event that one of the two transmission lines that serve the Central D.C. area is out of service (due either to a necessary planned outage or to unforeseen events) and sufficient electricity from the Mirant power plant were not available, then the Central D.C. area would experience an immediate blackout should the one remaining source of electricity fail. This situation must be avoided, and ordering paragraph A of this order ensures that this situation will be avoided. When an outage is planned, Mirant is to be given advance notice and is required to supply necessary generation throughout the period of the outage.\(^10\) In the event of an unexpected outage, Mirant must provide such generation as soon as possible. In the very unlikely eventuality of both transmission lines failing at the same time, Mirant is required to provide sufficient generation to supply the electrical demands of the affected area as soon as possible.

It is essential to determine the level of operation and other steps that will enable Mirant to rapidly respond to an unplanned transmission line outage. Some commenters have urged the Department to order the Plant to run continuously, even if doing so causes ongoing exceedances of the NAAQS. This would assure a high level of reliability of the electricity supply, but of course would not be tailored to particular circumstances in which operation of the Plant would be most necessary to provide needed reliability for the Central D.C. area and might also cause local air quality concerns. Other commenters have urged the Department to do nothing.

\(^9\) Demand response programs prompt electricity customers to reduce demand, especially during periods of short supply.

\(^10\) In making certain portions of this order effective only upon notice to Mirant by PEPCO of a planned or unplanned outage of one or both of the 230 kV lines, it is similar to the FPA section 202(c) orders issued during the 2000/2001 California energy crisis. In those, DOE ordered certain entities to generate, deliver, interchange and transmit electricity to the California Independent System Operator (California ISO), but the entities were not required to deliver energy or services unless the California ISO had filed with DOE a certificate that it had been unable to acquire adequate supplies of electricity in the market. \textit{See} Order pursuant to Section 202(c) of the Federal Power Act (December 14, 2000); Order Pursuant to Section 202(c) of the Federal Power Act (January 11, 2001).
The Department is not prepared to order actions that could cause more localized NAAQS exceedances than are necessary in order to assure adequate electric reliability for the Central D.C. area. At the same time, the Department should address the risks that delays in responding to an unplanned transmission line outage would present if measures are available to mitigate that risk. In my judgment, the appropriate balance is struck by (1) requiring Mirant to keep as many units in operation, and take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electrical reliability, as feasible (as further defined in the ordering paragraphs below). Thus, Mirant must take actions to reduce the time it takes to respond to an unplanned outage. This will serve to reduce the risk of a blackout but not at the price of unnecessary exceedances of health-based NAAQS. As Mirant improves its environmental performance, in cooperation with environmental regulators, its ability to react to an unforeseen outage also will improve. Environmental regulators and Mirant can work together, with the Department, to reduce, and perhaps eliminate, any conflict between environmental goals and electric reliability.

This order is effective immediately and will terminate at 12:01 a.m. October 1, 2006. This order may be modified or extended at any time upon order of the Secretary of Energy.

VI. Ordering Paragraphs

For the reasons set forth above, pursuant to section 202(c) of the Federal Power Act, it is hereby ordered that:

A. During any period in which one or both of the 230kV lines serving the Central D.C. area is out of service, whether planned or unplanned, Mirant will operate the Potomac River Generating Plant to produce the amount of power (up to its full capacity) needed to meet demand in the Central D.C. area as specified by PJM for the duration of the outage.

In the event of a planned outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand.

In the event of an unplanned 230 kV line outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand as soon as possible.

When producing electricity pursuant to this paragraph, Mirant shall utilize pollution control equipment and measures to the maximum extent possible to minimize the magnitude and duration of any exceedance of the NAAQS.

B. Mirant shall keep as many units in operation, and shall take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electricity reliability, as “feasible.” For purposes of this paragraph, “feasible” means as determined by the Department of Energy, after consideration of the plan submitted by Mirant pursuant to paragraph D of this order and after consultation with the Environmental Protection Agency, without regard to cost and without causing or significantly contributing to any exceedance of the NAAQS.
C. Notice

In instances of scheduled outages of one of the 230kV lines, PEPCO will give advance notice of the planned outage and the estimated duration of such outage to Mirant, PJM, DOE, FERC, EPA, and DEQ. The notice must be sufficiently in advance of the outage to allow Mirant to bring the required amount of generation needed for reliability purposes on line by the time the outage is scheduled. PEPCO will ensure that only those planned outages needed to maintain or enhance the reliability of the 230 kV lines (or to install new lines) are scheduled and that such outages are scheduled to minimize the environmental effects of the operation of the Plant.

PEPCO will notify DOE, PJM, FERC, EPA, and DEQ of any unplanned outage of one or both of the 230 kV lines as soon as possible, but in no event later than two hours after informing Mirant.

In the event of either a planned or unplanned outage, PJM will specify the amount of electricity that Mirant must provide in order to meet demand.

D. Mirant shall submit a plan to DOE, within 10 days of the date of this order, detailing the steps it will take to ensure compliance with this order. This compliance plan shall include, at minimum, information regarding adequate staffing, materials, and supplies; emissions controls; and length of time necessary to start-up the Plant’s generating units in the event of an unplanned or planned outage. DOE will review the compliance plan and order additional requirements if necessary.

E. Pursuant to the terms of FPA section 202(c) and DOE regulations at 10 C.F.R. § 205.376, Mirant and its customers should agree to mutually satisfactory terms for any costs incurred by Mirant under this order. If no agreement can be reached, just and reasonable terms shall be established by a supplemental order.

F. DOE expects that the DCPSC will take all reasonable actions to augment electrical reliability and to reduce electricity demand in the Central D.C. area.

G. DOE will periodically reexamine the need for this order with particular emphasis on: (1) Mirant’s progress, working with environmental regulators, in reducing emissions and/or the impact of emissions; and (2) whether the DCPSC is taking all reasonable actions available to it to support electricity reliability in the Central D.C. area.

H. Pursuant to section 313 of the Federal Power Act (16 U.S.C. § 8251), any person, State, municipality, or State commission that is a party to this proceeding and is aggrieved by this order may apply for a rehearing within thirty days. Requests for rehearing may be submitted by mail, facsimile, or electronic mail to the following: (1) mail should be directed to Lawrence Mansueti of the Permitting, Siting, and Analysis Division of the Office of Electricity Delivery and Energy Reliability at the United States Department of Energy, Routing Symbol OE-20, 1000
Independence Avenue, S.W., Washington, D.C. 20585; (2) facsimiles may be submitted to 202-586-5860; (3) e-mail may be submitted to Lawrence.Mansueti@hq.doc.gov.

Issued in Washington, D.C. at 1:45 p.m. this 20th day of December, 2005.

Samuel W. Bodman
Secretary of Energy
Exhibit C
Federal Power Act Clarification to
Ensure Reliable Emergency Grid Operation

Issue
There currently exists a conflict between the authority of the Department of Energy (DOE) to direct emergency operation of electric generation plants to maintain the reliability of the bulk power system and environmental laws. These conflicting legal mandates threaten the reliability of the grid and place the owners of power plants in the untenable position of having to choose compliance with one law over another.

Background
Section 202(c) of the Federal Power Act (FPA) gives the DOE the authority to order an electric generating facility to operate to avoid a reliability emergency. At times, environmental laws and regulations may restrict the operation of such generation unit. If a generation unit is ordered by DOE to operate under Section 202(c), and at the same time is prohibited from operating due to environmental limitations, the owner is faced with the dilemma of either violating an order from DOE or violating the existing environmental law.

Prior Occurrence
Mirant (now GenOn) faced this dilemma in 2005 when DOE Ordered the Potomac River Generating Station to operate to protect the electric supply to Washington DC. Mirant complied with the order and was later fined by the Virginia Department of Environmental Quality for a 3 hours NAAQS violation. If Mirant had had been forced to violate a plant-specific environmental permit limit in order to comply with the DOE order, it would have faced unlimited liability from a citizen law suit under the Clean Air Act.

Growing Concern
Over time, due to increasingly strict environmental regulations, there will be an increase in the occurrences of conflicting emergency reliability and environmental directives. Absent legislative action, the risks and costs associated with temporary non-compliance with environmental requirements could prohibit a company from complying with DOE emergency directives thus jeopardizing grid reliability.

Solution
The FPA must be amended to clarify that when a company is under an emergency directive to operate pursuant to Section 202(c) of the FPA by the Secretary of Energy, it will not be deemed in violation of environmental laws or subject to civil or criminal liability as a result of actions to comply with such emergency order.
The FPA should be amended to add the following at the end of existing Section 202(c):

No person shall be found or deemed to be in violation of, or subject to civil or criminal liability under, any environmental laws (including but not limited to, the Clean Air Act, Federal Water Pollution Control Act, Solid Waste Disposal Act, the Safe Drinking Water Act, Endangered Species Act, and Comprehensive Environmental Response, Compensation and Liability Act) or analogous laws or regulations promulgated by any federal, state or local authority thereunder, as a result of actions taken to comply with an order of the Commission under this subsection (c). No federal, state or local authority shall consider actions taken to comply with such an order in determining whether a person is subject to or in compliance with any such environmental law or regulations, nor shall a federal, state or local authority directly or indirectly require any additional permit under any such environmental laws as a result of actions taken to comply with such an order.
Exhibit D
ARTICLE XIII. EXCISE TAX ON MAJOR EMITTERS OF CARBON DIOXIDE.

Sec. 52-95. Findings.

The County Council finds that:

(a) In December, 2009 the US Environmental Protection Agency found that greenhouse gases in the atmosphere endanger both the public health and the environment for current and future generations.

(b) Montgomery County has embraced an 80% reduction in greenhouse gas emissions by 2050 and has begun to engage in programmatic efforts to reduce these emissions. These efforts constitute a significant investment by the County and its constituents and cover both stationary sources (County owned and otherwise) and mobile sources.

(c) It is appropriate that the largest emitters of carbon dioxide in the County contribute to paying for these greenhouse gas reduction programs. (2010 L.M.C., ch. 20, § 1.)

Sec. 52-96. Tax levied; rates.

(a) Any major emitter of carbon dioxide, as defined in subsection (b), must file a tax return and pay an excise tax each year on the privilege of emitting carbon dioxide into the County airshed.

(b) A major emitter of carbon dioxide is any person who owns or operates any stationary source of carbon dioxide located in the County that emits more than 1 million tons of carbon dioxide in any calendar year.

(c) The rate of the tax established under subsection (a) is $5 per ton of carbon dioxide emitted.

(d) The County Council by resolution, after a public hearing advertised under Section 52-17(c), may increase or decrease the rate set in subsection (c).

(e) As used in this Article:

(1) *Ton*, when applied to carbon dioxide in gaseous form, means the amount of gas in cubic feet which is the equivalent of 2000 pounds on a molecular weight basis.
(2) Director means the Director of Finance.

(3) Person includes any individual, business, corporation, association, firm, partnership, group of individuals acting as a unit, trustee, receiver, assignee, or personal representative.

(f) By regulations issued under method (2) that are consistent with this Article, the County Executive may further specify the administration of this tax. These regulations must identify the source of verifiable and measurable emissions data, which must be a federal or state air pollution control agency, on which the Director must base the amount of tax due. \(2010\ L.M.C.,\ ch.\ 20,\ §\ 1;\ 2010\ L.M.C.,\ ch.\ 49,\ §\ 1.\)

Editor's note—\textit{2010 L.M.C., ch. 20, § 3,} states: Revenue Allocation Suspended. Notwithstanding County Code Section 52-100, as enacted by Section 1 of this Act, the revenue received from the tax levied under County Code Section 52-96 in the first full fiscal year the tax collected must be held in a special reserve account.

Sec. 52-97. Credit.

(a) The Director must allow a credit against any tax due in an amount that reflects the proportionate reduction in carbon dioxide emitted from any source in the County if that reduction is attributable to any County greenhouse gas reduction program funded by revenue from this tax that is allocated under Section 52-100, compared to the amount of carbon dioxide emitted in the previous calendar year by each major emitter of carbon dioxide.

(b) The Executive by regulation must further define which reductions in emissions are considered in calculating this credit and how those reductions are measured. \(2010\ L.M.C.,\ ch.\ 20,\ §\ 1.\)

Sec. 52-98. Due date.

(a) The tax levied under Section 52-96 is due and payable for each month on the last day of the next month. Each person subject to this tax must file a report each month on a form supplied by the Director.

(b) The Director may establish an alternative payment system. If an alternative payment system is established, the Director must require a pro-rated payment for any taxable period that ends before the system takes effect. \(2010\ L.M.C.,\ ch.\ 20,\ §\ 1.\)

Sec. 52-99. Collection; interest and penalties; violation; lien.

(a) If any person does not pay the Director the tax due under Section 52-96, that person is liable for:
(1) interest on the unpaid tax at the rate of one percent per month for each month or part of a month after the tax is due; and

(2) a penalty of 5 percent of the amount of the tax per month or part of a month after the tax is due, not to exceed 25 percent of the tax.

The Director must collect any interest and penalty as part of the tax.

(b) If any person does not file a report or pay the tax when due, the Director must obtain information on which to calculate the tax due and may estimate the tax due based on the previous month’s tax or any other reasonable basis. As soon as the Director obtains sufficient information on which to calculate any tax due, the Director must assess the tax and penalties against the person. The Director must notify the person of the total amount of the tax, interest, and penalties by mail sent to the person’s last known address. This notice is prima facie evidence of the tax due; entitles the County to judgment for the amount of the tax, penalty, and interest listed in the notice; and gives the taxpayer the burden of proving that the tax has been paid or any other sufficient defense to the action. The total amount due must be paid within 10 days after the date of the notice.

(c) Every person liable for any tax under Section 52-96 must preserve for 3 years suitable records necessary to determine the amount of the tax. The Director may inspect and audit the records at any reasonable time.

(d) Any failure to pay the tax when due under Section 52-98, and any violation of Section 52-98 of this Section, is a Class A violation. Each violation is a separate offense. A conviction under this subsection does not relieve any person from paying the tax.

(e) Section 52-18D applies to this tax. (2010 L.M.C., ch. 20, § 1; 2010 L.M.C., ch. 49, § 1.)

Sec. 52-100. Allocation of Revenue.

Of the revenue from the tax levied under Section 52-96, 50% must be reserved for and allocated in the annual operating budget to funding for County greenhouse gas reduction programs, including mass transit. (2010 L.M.C., ch. 20, § 1.)

Editor’s note—2010 L.M.C., ch. 20, § 3, states: Revenue Allocation Suspended. Notwithstanding County Code Section 52-100, as enacted by Section 1 of this Act, the revenue received from the tax levied under County Code Section 52-96 in the first full fiscal year the tax is collected must be held in a special reserve account.

Notes

[Note] *Editor’s note—See County Attorney Opinion dated 1/26/98 analyzing a petition to
amend charter to require any increase in taxes to be approved by referendum. **Cross reference**-Authority to levy tax for charitable or social relief, § 37-1; revenue authority, ch. 42; parking lot taxing districts, ch. 60; special taxing districts, chs. 61-70; suburban transit district, ch. 87.

[Note]  
*Editor's note*-Blumenthal v. Clerk of the Circuit Court for Anne Arundel County, 278 Md. 398, 365 A.2d 279 (1976), addressed the right of the County to fix the amount of the recordation tax by ordinance adopted after adoption of enabling legislation, but prior to effective date of enabling legislation. The farmland transfer tax levied by this article (Sections 52-19 through 52-27) is constitutional. Vournas v. Montgomery County, 300 Md. 123, 476 A.2d 705 (1984).

[Note]  
*State law reference*-Tax credit authorized, Ann. Code of Md., art. 81, § 12E.

[Note]  

[Note]  
*Editor's note*-Article V, "Public Advocate for Assessments and Taxation," § 52-40, derived from 1974 L.M.C., ch. 28, § 1, and 1986 L.M.C., ch. 37, § 3, was repealed by 1993 L.M.C., ch. 44, § 1. See § 20-41A.

[Note]  
**Cross reference**-Historic preservation, ch. 24A.

[Note]  
*Editor's note*-See County Attorney Opinion dated 5/21/92 explaining that the construction excise tax is payable only if a building permit is issued and construction takes place. Former Article VIII, relative to excise tax on certain construction, derived from CY 1991 L.M.C., ch. 44, § 1 and 1994 L.M.C., ch. 14, § 1, was repealed by 1995 L.M.C., ch. 15, § 1.

---

Disclaimer:
This Code of Ordinances and/or any other documents that appear on this site may not reflect the most current legislation adopted by the Municipality. American Legal Publishing Corporation provides these documents for informational purposes only. These documents should not be relied upon as the definitive authority for local legislation. Additionally, the formatting and pagination of the posted documents varies from the formatting and pagination of the official copy. The official printed copy of a Code of Ordinances should be consulted prior to any action being taken.

For further information regarding the official version of any of this Code of Ordinances or other documents posted on this site, please contact the Municipality directly or contact American Legal Publishing toll-free at 800-445-5588.

© 2011 American Legal Publishing Corporation

techsupport@amlegal.com

1.800.445.5588
Northeast Bar Association

June 7, 2011

Doug Egan, Chief Executive Officer
Competitive Power Ventures, Inc.
About Competitive Power Ventures

- A leading North American energy project development and asset management company
- Founded in 1999 with headquarters in Washington, D.C. and offices in Boston, MA; San Francisco, CA and Toronto, Ontario; 70 employees
- A “blue chip” senior management team
  - CPV’s management team has developed over 20,000 MW of greenfield projects that are in operation in North America
  - The management team has collectively acquired and monetized more than $10 billion in power generation assets
- Development and management portfolio
  - Nearly 5,965 MWs of natural gas-fired generation projects currently in various stages of development in New England, New York, PJM, Ontario and California
  - Managing over 4,889 MWs of natural gas-fired generating facilities in New England, New York, PJM, Mississippi, California and Arizona
  - Currently developing 4,452 MWs of wind power and photovoltaic projects across North America
RPM Base Residual Auction
Resource Clearing Prices (RCP)


source: PJM 2014/2015 RPM Base Residual Auction Results - PJM DOCS #645284
PJM Generating Capacity (MW) by Age

as of 3/31/11

Coal (Steam) & Fleet Total

MWs

NERC Eastern Interconnection Coal Generation Retirement Projections

(Combined EPA Regulations / Moderate Case / by 2018)

Totals for Eastern Interconnection:
Derated: 5,689
Retired: 27,092
Total: 32,780

Table 10: Combined EPA Regulations Impacts - 2018
Levelized electricity costs for new power plants 2020 and 2035 (2009 cents per kilowatthour)

- **2020**
  - Coal
  - Nuclear
  - Wind
  - Natural gas combined cycle

- **2035**
  - Coal
  - Nuclear
  - Wind
  - Natural gas combined cycle

U. S. Natural Gas vs. Coal Prices
2000 - 2011

Source: EIA Annual Energy Outlook 2011, April 2011, EIA Natural Gas Prices
Contact

Doug Egan
CEO
Phone: 240-723-2302
degan@cpv.com

Competitive Power Ventures, Inc.
8403 Colesville Road, Suite 915
Silver Spring, Maryland 20910

- Headquarters
  Washington D.C.
  8403 Colesville Road, Suite 915
  Silver Spring, Maryland 20910
  240-723-2300

- Boston
  50 Braintree Hill Office Park, Suite 300
  Braintree, Massachusetts 02184
  781-848-0253

- San Francisco
  55 2nd Street, Suite 525
  San Francisco, California 94105
  415-293-1455

- Toronto, Ontario
  366 Bay Street, Suite 1100
  Toronto, Ontario M5H 4B2
  Canada
System Planning and Operational Responses
To Reliability Concerns and Policy Initiatives
Transmission Planning Over the Years

YESTERDAY
Build to deliver base-load generation (coal, nuclear) to load centers

TODAY
Build to keep the lights on and to reduce congestion & uplift costs

TOMORROW?
Build to meet environmental and public policy objectives?
STAGE 1
Consolidation of TO plans; Focus on intra-regional reliability only

STAGE 2
RTO/ISO plan preparation with TO input; some consideration of economic / market efficiency issues

STAGE 3
Formal incorporation of economic / market efficiency planning process; Consideration of other issues (e.g., inter-regional, renewables, emissions)

STAGE 4
Formal incorporation of other criteria and inter-regional issues (e.g., fuel mix, renewables, emissions)

Evolution of RTO/ISO Transmission Planning Processes
Who Pays?

The Transmission Cost Allocation Spectrum

Beneficiaries Pay / Participant Funding

Full Socialization / Network-wide Roll-in

Where are we?
Thanks!

• The content and opinions in this presentation are my own and may not necessarily represent the views or opinions of ESAI Power or any of its clients.
• Questions? jrotger@ESAI.com; (781) 245-2036

ESAI’s Northeast Power Service provides a series of reports with in-depth views of the Northeast (PJM, NY & NE) power markets. Reports include:

Northeast Energy Watch Quarterly – 10-year analysis and outlook of market prices and policy issues.

Northeast Energy Watch Monthly – 6-month zonal pricing forecast & review of policy and market changes.

Northeast Bi-Weekly – 1-week review & outlook for price analysis & trading.

Capacity Watch – Quarterly analysis of capacity markets & policy issues.

Transmission Watch & Memos – Quarterly & monthly analysis of transmission investment and development from a national perspective.

Congestion Watch – Monthly analysis of next month’s congestion and nodal pricing dynamics in the Northeast.

Natural Gas FundWatch – 1-week outlook & analysis of key near term factors in natural gas market.
The Changing Shape of System Planning:
“When the facts change, I change my mind. What do you do, sir?”

Seth Kaplan
Vice President for Policy and Climate Advocacy
Conservation Law Foundation

Energy Bar Association Northeast Chapter Annual Meeting
“Options for Meeting Emerging Reliability Needs and Public Policy Initiatives in the Northeast”

June 7, 2011
When you have over 90% of the world’s scientists who have studied this stating that climate change is occurring and that humans play a contributing role it’s time to defer to the experts. Climate science is complex though and we’re just beginning to have a fuller understanding of humans’ role in all of this. But we know enough to know that we are at least a part of the problem. So looking forward, we need to work to put policies in place that act at reducing those contributing factors.” NJ Gov. Chris Christie, May 26, 2011.

- Environmental imperatives and low gas prices = farewell to coal
- Rise of Demand Resources (Efficiency and Demand Response) as important player
- Unbundling continues: new products and services emerge like Frequency Regulation
- With this much change you are either adapting or fighting the future – question is how and how quickly we will change (decarbonize, etc…) not if it will happen . . .
Planning for a very different future . . .

A sketch of the exterior of Edison’s Pearl Street station.


Illustration taken from slide created by Alan Friefeld of Viridity Energy, who seems to have taken it from iTeres
While Inertia is strong, many forces pressing for change

- Emissions Reduction – Public Health
- Water Use/Discharge
- Environmental
  - Climate: electricity is the “hinge” sector
- Electric System Benefits
  - Diversification /Reliability: Japan shows wind can help keep the lights on
  - Zero fuel cost resources – price stability
- Economic
  - Self sufficiency, independence
  - Every place has indigenous renewable & demand resources (unlike fossil fuels)
- Political
  - Popularity should matter in a democracy
  - Jobs, attract employers, jobs, local property taxes, jobs and of course jobs

For a thriving New England
Legal Issues

- Existing legal and regulatory structures are legacies from a very different world:
  - Even ones that were progressive in their time can impede progress now –
    - PURPA is prime example, mandated purchase of power from renewables and other “Qualified Facilities” (“QFs”) at “avoided cost” now crashing into state net metering and feed-in tariffs
    - Open Access Transmission Tariffs – blew open the system, made gas and wind IPP industries possible but the concept now limits development of dedicated lines.

- That creaking noise you hear is the sound of state-federal balance shifting
  - What is federally regulated “transmission” and what is state regulated “distribution”?
    - For some technical purposes the line is kind of bright – but a lot of complexity here
    - Section 201(b) of FPA provides FERC with jurisdiction over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce" and section 205 prohibits unreasonable rates and undue discrimination "with respect to any transmission or sale subject to the [Commission's] jurisdiction." – does this give FERC jurisdiction to the toaster? When is electricity NOT in interstate commerce?

- Queasiness over FERC action at retail level – is that horse out of the barn? FERC ability to approve “gap RFPs” and compensate (and regulate) retail resources is well established and foreshadow fundamental change in the Fed – State balance.

- Unsurprisingly, money is biggest issue – what resources get paid (Non-transmission alternatives?) and who pays (cost allocation – state/regional/national)
Role of Energy Efficiency, Demand Response and New Technologies
Demand-side Resources and New Technologies

Energy Bar Association
June 7, 2011

Roddy Diotalevi
The United Illuminating Company
UIL – A Regulated Electric & Gas Co.

UIL Holdings Corporation

The United Illuminating Company (UI)
- Service territory: 335 sq miles
- ~325,000 customers
- 1,095 employees
- 50% interest in GenConn Energy LLC

Southern Connecticut Gas (SCG)
- Service territory: 512 sq miles from Westport, CT to Old Saybrook, CT
- ~178,000 customers
- 290 employees
- 2,269 miles of mains with ~131,000 services

Connecticut Natural Gas (CNG)
- Service territory: 716 sq miles - Greater Hartford-New Britain & Greenwich
- ~160,000 customers
- 319 employees
- 2,011 miles of mains with ~124,000 services

Berkshire Gas Company (Berkshire)
- Service territory: 738 sq miles in Western MA including Pittsfield and North Adams
- ~36,000 customers
- 120 employees
- 738 miles of mains

Service Area Key
- UI
- SCG
- CNG
- Berkshire
- Overlapping Territory
Fundamentally, What Are We Trying To Achieve?

Key factors on meeting our energy needs

- Energy Policy
  - Promoting energy efficiency, renewable energy and emerging energy technologies
- Economic Factors
  - High rates and economic slowdown highlight the need to be price sensitive
- Electric System constraints & benefits
  - Diversification of resources
  - Interconnection and transmission planning policies
- Environmental concerns
  - Existing power plant fleet
- Political in nature
  - A stakeholder process; popularity matters
Federal Energy Policy

- Emphasis on a “green economy”
  - 80% of power from "cleaner" sources like wind and solar, as well as nuclear, natural gas and clean coal by 2035.
  - National Renewable Portfolio standard
  - Climate Change Legislation?

- FERC Orders
  - April 13, 2011, Order in the FCM Re-Design proceeding
    - OOM resources, Alternative Pricing Rule, etc.
  - March 15, 2011, Order 745 (Docket No. RM10-17-000)
    - Requires demand resources to participate in wholesale energy markets and be compensated the same as generating assets
Regional Situation

• ISO-NE and the regional planning process
  – Older fossil units, Demand Resources, Imports, Intermittent resources, Transmission

• In NE, future energy mix will revolve around natural gas

• The NE electric system load factor has been steadily declining over time resulting in isolated periods of peak demand, higher energy and capacity costs, and higher average rates

Load Duration Curve

For less than 60 hours per year, New England needs an additional 2,500 MW of capacity to serve load
State Initiatives

• Connecticut Energy Efficiency Fund (created in 1998) established EE as a cornerstone of Connecticut energy policy
  – Borrowing from fund to balance the budget

• Renewable Portfolio Standards
  – Class I mandate of 20% of load by 2020; total of all classes is 27% by 2020

• 2011 Legislative Session
  – New tax on generators
  – SB-1
    • Creation of Department of Energy and Environmental Policy (DEEP) to coordinate energy policy with environmental rule-making
    • Shows some commitment to large-scale renewable development
The Pool of Resources

• Supply side
  – Aging coal and oil units
  – Major dependence on natural gas
  – Vermont Yankee license extension beyond 2012?
  – Capacity surplus may be overstated

• Demand side
  – Energy Efficiency
  – Demand Response
  – New technologies
    • Smart Grid
    • Home Area Network
    • Electric Vehicles
ISO-NE Demand Resources Clearing in FCM

- Energy efficiency
- Real-Time Demand Response
- Real-Time Emergency Generation

<table>
<thead>
<tr>
<th>Year</th>
<th>FCA_1</th>
<th>FCA_2</th>
<th>FCA_3</th>
<th>FCA_4</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010-2011</td>
<td>655</td>
<td>759</td>
<td>630</td>
<td>688</td>
</tr>
<tr>
<td>2011-2012</td>
<td>875</td>
<td>890</td>
<td>975</td>
<td>1167</td>
</tr>
<tr>
<td>2012-2013</td>
<td>978</td>
<td>1195</td>
<td>1206</td>
<td>1367</td>
</tr>
<tr>
<td>2013-2014</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total ICR (MW)
- 2010-2011: 32,305
- 2011-2012: 32,528
- 2012-2013: 31,965
- 2013-2014: 32,127
Energy Efficiency

- EE in the FCM continues to rise comprising over 1150 MW (4% of ICR) for FCA_4
  - Energy Efficiency is 67% Cheaper than ANY other Supply Option (Source: NEEP)

- CT’s Integrated Resource Plan encourages the adoption of the all cost-effective CLM option

- EE resources are ‘passive’ in nature and can not be scheduled or dispatched in response to system conditions
Demand Response

- Effective demand response can be implemented quickly, enhance grid reliability, and help reduce electric price volatility

- In the ISO-NE FCM, the role of DR continues to change
  - Fully integrated and included as capacity resources
    - Treatment of DR assets
    - Frequency of calls
    - Performance measurement
    - Capacity Payments

- FERC Order 745 – DR soon to be integrated into energy market

- Customer response and commitment is a concern
  - ‘Active resources’ where real, measurable action required to reduce load
New Technologies

- Smart Grid
  - Modernization of the electricity delivery system to optimize its operation (Conservation Voltage Reduction)
  - Enable next generation EE, DR, EVs, and smart appliances
  - Allow for better integration of distributed resources and energy storage
    - Real-time information of grid conditions and the effect of non-traditional resources on its operation

- Home Area Network (HAN) & Dynamic Pricing
  - Educate customers on energy consumption to help them better manage their usage
  - Enable residential DR
New Technologies

- **UI’s HAN Pilot**
  - Evaluate HAN system solution including devices, software, and implementation process in order to determine costs, benefits, and potential program offerings to the customer
  - 1,000 homes in (8) treatment groups

- **Electric Vehicles**
  - EV’s are coming
    - CT’s goal is 25,000 by 2020
  - Assess impact to distribution system
    - Clustering issues
  - Build-out of EV charging infrastructure
    - EVSE pilot for fifteen public charging stations
  - Assess future opportunities, such as “Smart Charging” and “Vehicle-2-Grid”
Questions

Roddy Diotalevi
Senior Director of Client Services
The United Illuminating Company
(203) 499-3632
roddy.diotalevi@uinet.com
BIOGRAPHIES
MARK BABULA is a Principal Engineer in the Resource Adequacy Department of System Planning at ISO New England Inc., Holyoke, Massachusetts. Mr. Babula graduated from Western New England College (1982) with a Bachelors degree in Electrical Engineering and from Rensselaer Polytechnic Institute (1987) with a Masters degree in Computer Science.

Mr. BABULA’s responsibilities at ISO New England include analysis of bulk electric power system reliability, generating unit availability and fuel analysis, environmental analysis, regulatory filings and governmental liaison. He also serves as technical lead on issues pertaining to natural gas use within the electric generation sector. Mr. Babula is Co-Chair of ISO New England’s Electric/Gas Operations Committee (EGOC) and he provides technical support to the NEPOOL Reliability Committee (RC), the Power Supply Planning Committee (PSPC), and the Environmental Advisory Group (EAG).

05/04/11-mrb
ANDREW K. DEMBIA

BIO

Andrew K. Dembia joined the New Jersey Board of Public Utilities (BPU) in September 2010 as a Legal Specialist with the Office of Chief Counsel specializing in federal and state energy policy issues. Prior to joining the BPU, Mr. Dembia was an Assistant General Regulatory Counsel representing the PSEG Companies before the BPU and the Federal Energy Regulatory Commission on various rate matters. Before his tenure with the PSEG Law Department, he was as an attorney in PSE&G’s Office of Corporate Rate Counsel since 2004 handling a variety of natural gas and electric regulatory matters on the state level. Mr. Dembia also served as the Election Law Enforcement Commission liaison between various utility business units and the Corporate Compliance Officer and was responsible for ensuring compliance with reporting requirements for registered governmental agents in the utility.

Before joining PSE&G, Mr. Dembia served in several positions over his eleven years with the New Jersey Division of Rate Counsel (Rate Counsel). During his tenure with Rate Counsel, Mr. Dembia successfully argued before the NJ Supreme Court and had the Court overturn an existing NJ Supreme Court Decision and Appellate Division decision allowing charitable contributions made by utilities to be recovered from ratepayers. In Re NJ-American Water Co., 169 NJ 181 (July 25, 2001). Mr. Dembia served as Deputy Director and was the agency’s designee on the New Jersey Clean Energy Council and the Governor’s Renewable Energy Taskforce. Mr. Dembia also served as the agency’s Emergency Coordinator and Ethics Liaison Officer. He also managed and supervised the Public Information Officer, Office Manager, Chief Accountant and IT Systems Manager. Prior to his service in state government, Mr. Dembia was in private practice with the firm of Stryker, Tams & Dill as an associate attorney representing various clients in the electricity, natural gas, water, telecommunications and cable TV industries.

For over 20 years, Mr. Dembia has been active across a broad range of energy issues, ranging from restructuring in the electric and natural gas industries to traditional rate regulation. Mr. Dembia has also been extensively involved in various utility mergers over his career.

Mr. Dembia is a member of the New Jersey and New York bars. Mr. Dembia graduated from New York Law School and from Rutgers University/Cook College with a Bachelor of Science degree in International Environmental Studies.
Roddy Diotalevi  
**Senior Director – Client Services**  
The United Illuminating Company

Roddy Diotalevi has nearly 30 years experience in the electric power industry and has been employed at The United Illuminating Company since 1986. As the Senior Director of Client Services he currently oversees UI’s account management group and business development activities including the company’s strategic plans around Electric Vehicles and Residential Smart Grid applications. In addition, Roddy is responsible for UI’s commercial/industrial product offerings as well as UI’s Demand Response Programs. Roddy has presented at the Northeast Sustainable Energy Association on the topic of smart grids and was an active member of Connecticut's Electric Vehicle Infrastructure Council, established in 2009 by executive order of former Governor Jodi Rell.

Roddy previously worked as an energy engineer implementing CLM projects at customer locations and earlier in his UI career held various positions in the power generation division eventually overseeing the maintenance activities at one of UI’s formerly-owned generating facilities.

Prior to his 25 years at UI, Roddy was employed by General Electric where he worked as a Nuclear Field Engineer. Roddy holds a Master of Business Administration degree from the John F. Welch College of Business at Sacred Heart University and a Bachelor of Science in Marine Engineering from the United States Merchant Marine Academy.
Joseph Dominguez

Position
Senior Vice President, Federal Regulatory Affairs, Public Policy, & Communications, Exelon; Senior Vice President, State Governmental Affairs, Exelon Generation

Profile
Dominguez leads federal regulatory affairs, public policy and communications for Exelon Corporation, one of the nation’s largest electric companies with more than $17 billion in annual revenues. In this role he oversees Exelon’s federal regulatory compliance, controls, government affairs and the communications that govern Exelon’s business activities. In addition, Dominguez is senior vice president of state governmental affairs for Exelon Generation Company which is the largest owner/operator of nuclear power plants in the United States. In this role he oversees Exelon Generation Company’s strategic efforts related to all state regulatory and legislative initiatives, and political advocacy.

Dominguez’s legal/engineering background and analytical approach to problem solving has and continues to play an important role in Exelon’s success. Dominguez is well respected by his peers and has been selected as a featured speaker at numerous national and regional industry conferences on a broad range of energy matters.

Professional History
Dominguez joined Exelon in 2002 as associate general counsel where he was responsible for all litigation matters in the Mid-Atlantic region. In 2004, he was named general counsel for PECO. He was named Senior Vice President of State Regulatory and Government Affairs and the General Counsel of Exelon Generation Company. In 2009, in addition to these roles Dominguez became Senior Vice President of Communications and in 2010 became Senior Vice President of Federal Regulatory Affairs & Public Policy for Exelon Corporation.

Prior to joining Exelon, Dominguez was a partner in the law firm of White and Williams, L.L.P., where he had a broad-based litigation practice counseling large and small corporations, institutions, government entities, and individuals. He is also a former assistant United States Attorney, Eastern District of Pennsylvania, where he spearheaded the investigation and prosecution of numerous crimes ranging from money laundering to murder-for-hire.

Civic Involvement
Dominguez has been a long standing contributor to the community in a variety of ways, and serves on Boards of Directors/Councils, such as the Corporate Advisory Board for APM (a health, human services, community and economic development non-profit organization helping Philadelphia area families) and the Corporate Advisory Council of Congreso de Latinos Unidos (a non-profit organization helping Philadelphia area families), volunteer work with a variety of non-profit organizations and other contributions. He has received several awards including the Michael K. Smith Excellence in Service Award from the Pennsylvania Bar Association.

Education
Dominguez has an undergraduate degree, with honors, in mechanical engineering from the New Jersey Institute of Technology which he attended on scholarship. He is a graduate of Rutgers University School of Law (High Honors), where he was named a Ralph Johnson Bunche Scholar and a Dean's Scholar.
Doug Egan Chairman & Chief Executive Officer

Doug co-founded CPV with Gary Lambert in 1999 and together they raised venture capital funding for the company in a series of separate financings, exceeding $300 million in total. Under his leadership, CPV has focused on traditional and renewable power generation project development and asset management services for major energy and finance industry clients and investors. Doug provides the strategic direction for the company as it responds to the evolution of a highly dynamic North American market. With more than 25 years in the independent power industry, he is well known to the power, natural gas and financial communities.

Prior to forming CPV, Doug was Senior Vice President for Development at PG&E Generating Company, formerly US Generating Company. At PG&E, he was responsible for non-regulated power project development. He was responsible for the initiation of seven natural gas fired power generation projects and a wind project representing more than 5,000 MW of capacity currently in operation across the United States. Prior to assuming control of PG&E's development program, Doug was Vice President and Regional Executive for their Northeast Region where he supervised six operating IPP projects, including fuel supply and transportation and power sale agreements.

Prior to PG&E, Doug was Vice President of Development at J. Makowski Company of Boston where he was responsible for the acquisition and financial restructuring of Altresco Financial, Inc. Additionally, he held the position of General Counsel for Intercontinental Energy Corporation of Hingham, Massachusetts through the development and construction of two cogeneration projects representing more than 600 MWs. In the early 1980's, Doug worked at the law firm of Murtha Cullina Richter & Pinney in Hartford, Connecticut.

Doug is a graduate of Dartmouth College and Cornell Law School.
Mason Emnett, Associate Director

Mason Emnett is Associate Director of the Office of Energy Policy and Innovation at the Federal Energy Regulatory Commission. The Office provides leadership in the development and formulation of policies and regulations to address emerging issues affecting wholesale and interstate energy markets.

Mr. Emnett joined the Commission in 2006, serving as Senior Legal Advisor in the Commission's Office of General Counsel. There he advised the Commission on legal and policy matters related to electric transmission service, wholesale power sales, electric system reliability, corporate regulation of public utilities, and enforcement proceedings. Prior to joining the Commission, Mr. Emnett was in private practice with the law firm of Skadden, Arps, Slate, Meagher and Flom LLP in Washington, D.C, where he represented public utilities appearing before the Commission on matters related to market design, wholesale rates, mergers and acquisitions, and regulatory compliance.

Mr. Emnett is a graduate of the Georgetown University Law Center and of the University of Texas at Arlington.
Natara G. Feller focuses her law practice on energy and public utility law. She regularly counsels clients on regulatory, transactional, compliance and enforcement matters involving the Federal Energy Regulatory Commission (FERC) and state utility commissions. Ms. Feller also advises clients on the requirements of the the North American Electric Reliability Council (NERC)'s mandatory Reliability Standards, the Federal Power Act, the Natural Gas Act, the Energy Policy Act of 2005, the Public Utility Holding Company Act, the Public Utility Regulatory Policy Act, and state and federal rules and regulations affecting the energy sector. Ms. Feller's clients have included power marketers, natural gas companies, public utilities, energy service companies, financial institutions, renewable power developers and qualifying facilities. Prior to practicing law in the private sector, Ms. Feller served as an Attorney-Advisor with the FERC Office of Administrative Law Judges.

**Ms. Feller's experience includes advising on matters related to:**
- Regulatory compliance obligations under the FPA, PURPA, PUHCA, NGA, NGPA, EPAct 2005 and state statutes
- the NERC Rules of Procedure and Reliability Standards
- Participation in organized markets and ISO/RTO governance
- Mergers, sales and acquisitions of FERC-jurisdictional assets
- Project development and generation interconnection
- Preparation of all manner of responsive agency pleadings, including rehearing applications, briefs, comments, testimony, protests and motions, natural gas tariff filings, QF and EWG self-certifications and market-based rate applications

**Admissions:**
Ms. Feller is admitted to practice in New York, New Jersey and the District of Columbia.

**Education:**
Ms. Feller graduated cum laude from Pace University School of Law in 2005 and earned a certificate in Environmental Law. Ms. Feller earned her B.A. in Environmental Studies and History in 1997 from Binghamton University.

**Professional Affiliations:**
- Secretary, Energy Committee of the New York City Bar Association (2009 - Present)
- Energy Bar Association
- Women's Council on Energy and the Environment

**Specialties**
- Energy Law
- Electric Reliability/NERC Compliance
- Regulatory/Compliance
Judith F. Judson  
Vice President of Asset Management and Market Development

Judith Judson was promoted to her current position and made an officer of Beacon Power in April 2010, after serving as the company's Director of Regulatory and Market Affairs since January 2008. She played a key role in the creation of tariffs within several deregulated electricity markets that now allow non-generation resources like Beacon's flywheels to participate, and she continues to lead the effort to help shape language in market rules and implement pay-for-performance-based compensation commensurate with Beacon's high-performance, fast-response technology. As head of asset management, Judith manages a team that is developing the company's merchant frequency regulation plants in the U.S. In that capacity she oversees site selection, plant development and interconnection, and is responsible for project management, budgets and schedules. As each plant is built, she will oversee operations and direct the regulation services bidding process so as to maximize Beacon's revenue and profit potential. Before Beacon, Judith worked for the Commonwealth of Massachusetts from 2003 through early 2007, where she rose to become the state's head energy and telecom regulator. As Chairwoman of the Mass. Department of Telecommunications and Energy, she managed a 150-person team to regulate the state's $11-billion energy industry and $4-billion telecom industry. Judith holds an MBA from Harvard Business School and a Bachelor's degree in Mechanical Engineering from Kettering University.
Seth Kaplan is the Vice President for Policy and Climate Advocacy at the Conservation Law Foundation overseeing all work at CLF involving global warming and greenhouse gas emissions.

A graduate of Wesleyan University and Northeastern University School of Law he worked as a real estate and environmental attorney in private practice in New York City before his return to CLF (where he had previously worked as a law student) in 1998. His current work focuses on fostering renewable energy, working for climate protection and reducing the environmental impact of fossil fuel power plants and pressing for expanded opportunities for meeting energy needs through energy efficiency. This work has included FERC litigation and extensive participation in ISO New England and New England Power Pool processes. In particular he has been deeply involved in the multi-state and stakeholder process that shaped the Regional Greenhouse Gas Initiative and the ISO New England process defining a new “Forward Capacity Market.”

He oversees policy development and advocacy at CLF that ranges from issues regarding public transit expansion, clean renewable energy infrastructure, energy efficiency and regulation of emissions from automobiles as well broader legal advocacy regarding greenhouse gas emissions and energy policy.

Previously, he directed CLF’s transportation work, which included advocating in favor of expanded and cleaner public transit, including a successful effort to substantially reduce emissions from the MBTA bus fleet.

More recently, his work focused on the electricity sector including FERC litigation and extensive participation in ISO New England and New England Power Pool processes and national policy debate and development regarding electricity transmission infrastructure. He has been deeply involved in the multi-state and stakeholder process that shaped the Regional Greenhouse Gas Initiative and the ISO New England process defining a new “Forward Capacity Market.”

A native of Rhode Island, he is the father of three children. His wife, also a graduate of Northeastern Law, teaches at Suffolk University Law School.
Commissioner Cheryl A. LaFleur

Commissioner Cheryl A. LaFleur was nominated by President Barack Obama to serve as a member of the Federal Energy Regulatory Commission and confirmed by the U.S. Senate for a term that ends in June 2014.

Commissioner LaFleur has more than 20 years experience as a leader in the electric and natural gas industry. She retired in 2007 as executive vice president and acting CEO of National Grid USA, responsible for the delivery of electricity to 3.4 million customers in the Northeast. Her previous positions at National Grid USA and its predecessor New England Electric System included chief operating officer, president of the New England distribution companies and general counsel. Earlier in her career, she was responsible for leading award-winning conservation and demand response programs for customers.

Commissioner LaFleur is a frequent speaker on energy issues, particularly reliability and grid security, transmission planning, and enabling clean energy resources. She is a member of the NARUC Committees on Electricity and Critical Infrastructure.

Commissioner LaFleur has been a nonprofit board member and leader, and has been honored by Bryant University, the Greater Boston Chamber of Commerce, and the YWCA of Central Massachusetts.

Commissioner LaFleur began her career as a lawyer at Ropes and Gray in Boston. She has a J.D. from Harvard Law School, where she was an editor of the Harvard Law Review, and an A.B. from Princeton University.

Commissioner LaFleur is married to William A. Kuncik, a retired attorney, and they are the parents of two grown children.

Sworn In: July 13, 2010
Term Expires: June 30, 2014

Staff:
Kim Shannon, Confidential Assistant
Joshua Konecni, Legal Advisor
Ruta Skucas, Legal Advisor
Kurt Longo, Technical Advisor
Patricia Herrion, Secretary

Contact Information:
202-502-8961
Suite 11-C
888 First Street, NE
Washington, DC 20426
Paul D. McCoy

Mr. McCoy currently serves as President of Trans-Elect Development Company, LLC. At Trans-Elect, McCoy leads the execution of the company’s electric transmission development plans, direct it’s regulatory and policy work, and oversees the operation of assets that the Company owns or controls.

He also serves as one of the Principals of the Atlantic Wind Connection ("AWC"). At AWC, he leads the contracting and procurement process and also manages the interaction of the AWC project with the PJM Interconnection, LLC’s Regional Transmission Expansion Plan process.

Prior to joining Trans-Elect, McCoy was Senior Vice President of Unicom, Senior Vice President of Commonwealth Edison (“ComEd”), and led the Transmission Group of ComEd in Chicago, Illinois. At ComEd/Unicom, he served for 7 years as a member of the senior executive policy team. McCoy had direct responsibility for a wide variety of activities at ComEd, including the planning, design, construction, and operation functions for its transmission and distribution systems.

McCoy has held a number of leadership positions involving major utility industry organizations. He has served as Chairman of the Mid-America Interconnected Network (MAIN), one of the NERC Reliability Councils, a board member of the North American Electric Reliability Council (NERC), Chairman of National Electric Energy Testing, Research & Applications Center at the Georgia Institute of Technology (NEETRAC), and a member of the Electric Power Research Institute (EPRI) Research Advisory Committee. He was a leader in the formation of the Midwest Independent System Operator (MISO), and served as the initial Vice-Chairman of its Transmission Owners’ Committee. McCoy is the immediate past-president WIRES, a national organization that promotes the economic expansion of a strong and well-planned electric transmission network.

McCoy has significant working experience with several State regulatory agencies (including Texas) and the Federal Energy Regulatory Commission (FERC) in a variety of formal and informal settings. He has spoken extensively at industry seminars and meetings for 20 years. He has appeared as a guest lecturer at the University of Illinois and the Illinois Institute of Technology.

McCoy is currently participating with the Illinois Institute of Technology under three Department of Energy grants as a partner/contractor. One is to develop a Market Simulation Tool for Facilitating Wind Energy Integration, the second is a University-Industry Consortium for Wind Energy Research, Education and Workforce Development and the third is to develop a World-Class Smart Grid Training Center.

He currently serves on AltaLink’s Board of Directors as an Independent Director, is Chairman of the Board’s Governance, Compensation and Human Resource Committee and is a member of AltaLink’s Large Project Committee. AltaLink, based in Calgary, is Canada’s only independent electric transmission company with assets of over $1.6 billion.
CURRENT PROFESSIONAL AFFILIATIONS
AltaLink Management, LLC – Independent member of the Board of Directors. Chairman of the Governance, Compensation, and Human Resource Committee of the Board. Member of the Large Projects Committee

Represent AWC within WIRES, a national coalition of companies that promotes the development of a strong and well-planned transmission system. WIRES is based in Washington, DC.

EDUCATION
Bachelor of Science Degree in Electrical Engineering, Illinois Institute of Technology, Chicago, 1972.

LICENSES AND CERTIFICATIONS
Licensed Professional Engineer, State of Illinois (License Number 062-037907) – Status- active

OTHER ACTIVITIES
Chairman of the Board of Trustees of De LaSalle Institute in Chicago, Illinois. De LaSalle is a Catholic high school located on Chicago’s South Side.

Member of the Board of Trustees of the Illinois Institute of Technology (IIT) in Chicago, Illinois. IIT is a leading Engineering and Architecture University.

Member of the Advisory Board of WISER (Wanger Institute for Sustainable Energy Research), based in Chicago.

Volunteer Training Coordinator and Logistics Team Leader with the Emergency Medical Corps/Emergency Management Services in Western Springs, Illinois (my hometown), a program of the Federal Emergency Management Agency (FEMA). Certified under IS-100, IS-200, IS-800 AND NIMS-700 of the National Emergency Management Institute under FEMA.
Richard Miller is Director of the Energy Markets Policy Group at Con Edison. 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.
Debra L. Raggio

Debra Raggio is Vice President and Assistant General Counsel, Government and Regulatory Affairs for GenOn Energy. Ms. Raggio has more than 25 years experience in a broad range of regulatory, compliance and transitional matters. Currently, Ms. Raggio oversees the federal legislative and regulatory issues, policies and legal matters for GenOn Energy. She is also responsible for the regulatory and legal matters in the states and Regional Transmission Organizations in which GenOn operates.

Prior to GenOn, Ms. Raggio’s work experience included positions with Mirant Corporation as Vice President and Assistant General Counsel representing Mirant in proceedings before the Federal Energy Regulatory Commissions as well as other federal agencies and appellate proceedings.

Ms. Raggio was an attorney with the law firm of Baker Botts, LLP specializing in regulatory and transactional energy matters and appellate litigation. Before working with Baker Botts, LLC, Ms. Raggio clerked for Chief Justice Tom R. Phillips of the Supreme Court of Texas.

Prior to receiving her J.D., Ms. Raggio marketed natural gas for Tenngasco Corporation, and prior to that she worked as a petroleum landman for Tenneco Oil Company, where she was responsible for land acquisition matters associated with exploration and development of natural gas and oil.

Ms. Raggio is a member of the Bars of Texas, the District of Columbia, the Fifth Circuit, and the Ninth Circuit.

Ms. Raggio has a J.D. from the University of Texas; MBA Finance and Management from the University of Houston and B.S., magna cum laude, in Mineral Land Management from the University of Colorado.
José Rotger Bio

With over 22 years of experience in the industry as a transmission developer, utility executive and state regulator, José Rotger specializes in competitive electricity markets and the role played by transmission issues in these markets. Mr. Rotger has been involved in NEPOOL since the mid-1990s, beginning with the Regional Transmission Group (“RTG”) discussions in 1994-95. Since 1999, Mr. Rotger has served as the NEPOOL committee representative for Cross-Sound Cable Company, LLC and its predecessor development company. Mr. Rotger also serves as the current Vice Chair of the NEPOOL Transmission Committee.

As Manager, Regulatory and RTO/ISO Affairs for ESAI Power LLC (“ESAI Power”), Mr. Rotger leads ESAI Power’s Transmission Watch service, providing monthly and quarterly analyses on transmission issues to our Northeast Power Service clients. Mr. Rotger is also a lead contributor to ESAI Power’s Capacity Watch and Northeast Energy Watch services, as well as special projects and other advisory services.

Previously, Mr. Rotger was Director, Regulatory Policy and Markets for TransÉnergie U.S. Ltd. (“TEUS”), a developer of independent transmission projects worldwide and the original developer of the Cross Sound Cable (“CSC”). In addition to his role as an architect of market-based frameworks for transmission project development, Mr. Rotger managed Federal and State regulatory affairs for various TEUS projects, including the CSC – the first market-based transmission project in the U.S.

Prior to TEUS Mr. Rotger was a Principal Rate Analyst for the New England Electric System (now National Grid), where he participated extensively in the company’s restructuring and divestiture efforts and managed all of New England Power Company’s generation and stranded cost-related filings before FERC. Mr. Rotger was also New England Power’s fuel adjustment cost witness before three state retail jurisdictions. Prior to NEES, Mr. Rotger served as an Economist with the Massachusetts Department of Public Utilities, where his five-year tenure included involvement in all aspects of utility rate cases and resource planning filings.

Mr. Rotger holds a Bachelors degree in Economics from Brown University and an MBA from Northeastern University. He has provided testimony before FERC, the U.S. Department of Energy, and various regulatory, siting, and legislative bodies in the states of Connecticut, Massachusetts, New Hampshire, New York, Pennsylvania, and Rhode Island.
Ralph Rufrano (Manager, NPCC Compliance Violation Investigations - Northeast Power Coordinating Council NPCC.

Ralph Rufrano has thirty five (35) years of utility industry experience, primarily in System Planning. He joined NPCC in January 2010. His career started at American Electric Power Corp., Inc and then on to the New York Power Authority (NYPa), where he spent the majority of his career. He worked himself up through the ranks of System Planning from Associate Engineer to Senior Engineer and then Supervisory Engineer, finally to be named Manager of Transmission Planning for NYPa. During his tenure he was intimately involved in the planning and licensing of such projects as: the 765KV project connecting New York State to Quebec, the Marcy South project through central NY and the Sound Cable project from Westchester to Long Island; as well as, serving as an expert witness during evidentiary hearings associated with Article VII proceedings before the Public Service Commission. He was also involved with various Article X generation interconnection studies, site selection and licensing. His professional growth later led him to become the Executive Director of Reliability Standards and Compliance responsible for the development of a compliance program for NYPa. Ralph also served on the Executive Committee of the New York State Reliability Council, including the NPCC Board of Directors; as well as, a number of technical Committees, Subcommittees, Task Forces and Working Groups of both NPCC and the New York Independent System Operator. Ralph holds a Bachelor of Science degree in Electrical Engineering from Manhattan College.
T. Michael Twomey is a utility executive with broad experience in the electric and telecommunications industries, including more than ten years of legal experience in private practice and as in-house counsel for investor-owned public utilities. Since July 2010, Mike has served as Vice President, External Affairs-Wholesale with responsibility for the oversight of Entergy’s state governmental relations issues in connection with its wholesale assets, including its non-utility nuclear units in Massachusetts, Michigan, New York, and Vermont. Mike joined Entergy as Assistant General Counsel-Regulatory in August 2002. From 2002 until he assumed his current role, Mike served in a series of legal and regulatory roles for Entergy’s utility operations in Arkansas, Louisiana, Mississippi, and Texas. Prior to joining Entergy, Mike was Senior Regulatory Counsel for BellSouth Telecommunications, Inc. in Atlanta, Georgia with responsibility for various matters pending before the state public service commissions in BellSouth’s nine-state region, including numerous matters related to the implementation of the Telecommunications Act of 1996. In addition to his experience with BellSouth, he was a partner with the New Orleans-based law firm of Jones, Walker, Waechter, Poitevent, Carrère & Denège, L.L.P., where he represented companies in a variety of complex matters, including appeals of public utility regulatory decisions, antitrust suits, class actions, breach of contract disputes, and other litigation matters pending in state and federal courts. Mike received his B.A. from Tulane University and his J.D., with honors, from the University of Connecticut.