

**STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES**

**IN THE MATTER OF THE PETITION OF :
PUBLIC SERVICE ELECTRIC AND GAS :
COMPANY FOR A DETERMINATION :
PURSUANT TO THE PROVISIONS OF :
N.J.S.A. 40:55D-19 : BPU DOCKET
:
(SUSQUEHANNA-ROSELAND) :
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**PRE-FILED DIRECT TESTIMONY OF STEVEN R. HERLING
ON BEHALF OF PUBLIC SERVICE ELECTRIC AND GAS
COMPANY IN SUPPORT OF SUSQUEHANNA-ROSELAND
TRANSMISSION LINE PROJECT**

I. BACKGROUND

Q. Please state your name and business address.

A. My name is Steven R. Herling and my business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497.

Q. By whom are you employed and in what capacity?

A. I am Vice President of Planning for PJM Interconnection, L.L.C. (“PJM”). As PJM’s Vice President of Planning, I am responsible for the Capacity Adequacy Planning Department, which develops the long-term load forecast for the PJM region and, in consultation with load-serving entities, sets and enforces requirements for the sufficiency, adequacy, and availability of the generation resources needed to ensure reliable service to loads; the Interconnection Planning Department, which evaluates interconnections to the transmission system by new

1 generation and merchant transmission projects; and the Transmission Planning
2 Department, which evaluates the reliability and market efficiency of the
3 transmission grid and develops the regional transmission expansion plan
4 (“RTEP”).

5 **Q. Please describe your professional experience and educational background.**

6 **A.** I have been employed by PJM since May 1990, when I began work as an
7 Engineer in the Operations Planning Department. I was promoted to Senior
8 Engineer in 1993 and to Manager of the System Planning Department in 1994. I
9 then held a number of management positions until I was promoted to Executive
10 Director, System Planning Division in 2003. I was promoted to my current
11 position in May 2004.

12 While at PJM, I have contributed to or led initiatives that resulted in a
13 wide range of milestone achievements in its evolution and growth as a regional
14 transmission organization (“RTO”), including the creation of the RTEP process,
15 the development of procedures and standard terms and conditions for generator
16 and merchant transmission interconnections, and the reliability and adequacy
17 aspects of successive integrations of additional control areas that have more than
18 doubled the size of the PJM market area.

19 In addition to my work for PJM, I have contributed to a wide range of
20 activities of the North American Electric Reliability Corporation (“NERC”)
21 (formerly the North American Electric Reliability Council) and previously served
22 as vice-chair of the NERC Planning Committee. I have also served on various
23 regional and industry working groups and committees addressing reliability and

1 planning matters. I have testified on a number of occasions on system planning
2 and reliability issues in proceedings before the Federal Energy Regulatory
3 Commission (“FERC”), state commissions, and legislative task forces. In
4 addition, I testified before the West Virginia, Virginia and Pennsylvania
5 Commissions in the TrAIL proceedings in 2008, discussing many of the same
6 issues I intend to address in this testimony.

7 Prior to joining PJM, I worked for the General Public Utilities Service
8 Corporation for three years in systems operations, where I was responsible for
9 dispatcher training and certification, operations planning activities, and energy
10 management system and operational support tools. Prior to that, I worked for the
11 American Electric Power Service Corporation for eight years in bulk transmission
12 planning. In that position, I performed a range of power system analyses related
13 to the AEP 765 kV transmission system, generator and circuit breaker dynamic
14 modeling, and the mechanical behavior of turbine-generator shaft systems.

15 I am a licensed Professional Engineer in the state of Ohio. I hold a
16 Bachelor of Science in Electrical Power Engineering and a Master of Engineering
17 in Electric Power Engineering, both from Rensselaer Polytechnic Institute.

18 **II. PURPOSE OF TESTIMONY**

19 **Q. Please describe the purpose of your testimony.**

20 **A.** I have been asked by Public Service Electric and Gas Company (“PSE&G”) to
21 describe PJM and its regional transmission expansion planning protocol
22 (“RTEPP”). In particular, I will discuss the Susquehanna - Roseland Project
23 (“Project”) in the context of the RTEPP. The Susquehanna - Roseland Project

1 consists of a 500-kV transmission line from the Susquehanna 500 kV substation
2 near Berwick, Pennsylvania, approximately 130 miles in length, to the existing
3 Roseland 230 kV substation Roseland, New Jersey.

4 **Q. What areas will you discuss in your testimony?**

5 **A.** In general terms, I will explain that as a federally-approved Regional
6 Transmission Organization (“RTO”), PJM is responsible to ensure the reliability
7 of the transmission grid in the PJM territory. In order to demonstrate compliance
8 with NERC Reliability Standards (“NERC Reliability Standards” or “Reliability
9 Standards”) PJM tests system conditions to evaluate the reliability of the
10 transmission system and then determines transmission solutions that are needed to
11 ensure that the criteria underlying the NERC Reliability Standards are met.
12 Pursuant to FERC authority, PJM may direct the building of new transmission
13 projects or upgrades to ensure grid reliability. The PJM planning process is open
14 and dynamic, and all decisions and analysis are subject to stakeholder review and
15 participation.

16 The need for the Susquehanna - Roseland Project, and its selection as the
17 appropriate mechanism to address that need, was determined through the RTEP
18 process in an open, transparent forum that afforded every opportunity to consider
19 alternative solutions for the Project. No alternative solution, including demand
20 response programs, additional generation, and/or alternative technologies, was
21 identified to obviate the need for this Project during the PJM RTEP process. PJM
22 forecasts reliability violations as early as 2012, if the Project is not completed on
23 schedule. Thus, the need for the Project is significant and urgent.

1 **Q. How is your testimony organized?**

2 **A.** My testimony is organized into the following sections:

- 3 • Description and Overview of PJM
- 4 • PJM Transmission Planning Process
- 5 • Role of FERC and NERC
- 6 • RTEP Results
- 7 • Changes Over Time to Planning Assumptions
- 8 • Alternatives Considered

9 **Q. What was your role in the development of the Susquehanna-Roseland**
10 **Project?**

11 **A.** As PJM’s Vice President of Planning, I have overall responsibility for all aspects
12 of the development of the RTEP, including the performance of all analyses, the
13 development and evaluation of solution options, interaction with PJM
14 stakeholders, documentation of the RTEP, and review with the PJM Board of
15 Managers (“PJM Board”). With respect to the PJM stakeholder process, I have
16 responsibility to ensure that the review of the RTEP is conducted through the
17 Transmission Expansion Advisory Committee and the Sub-Regional RTEP
18 Committees according to the provisions of the Amended and Restated Operating
19 Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”). I am also
20 responsible for the on going review with PJM stakeholders of the RTEP process
21 itself and the continuing development and implementation of improvements to that
22 process. I was involved in each of these capacities as PJM prepared its 2007 and

1 2008 RTEPs and selected the Susquehanna - Roseland Project as part of the
2 overall solution to the transmission reliability violations PJM had identified.

3
4 **III. DESCRIPTION AND OVERVIEW OF PJM**

5 **Q. Please describe PJM.**

6 **A.** PJM is an RTO that ensures the reliability of the electric transmission system
7 under its functional control and coordinates the movement of wholesale electricity
8 in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New
9 Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia
10 and the District of Columbia.

11 The PJM system serves approximately 51 million customers. PJM
12 dispatches more than 164,000 megawatts (“MW”) of generation capacity over
13 more than 56,000 miles of transmission lines – a system that serves nearly 20
14 percent of the United States economy. PJM’s wholesale electricity markets had
15 more than \$30 billion in billings in 2007.

16 PJM presently has more than 500 members. These members/customers
17 include power generators, transmission owners, electricity distributors, power
18 marketers and large consumers. PJM’s role as a federally-regulated RTO means
19 that it acts independently and impartially in operating and planning the regional
20 transmission system and in overseeing the wholesale electricity market.

21 **Q. What is the background leading to PJM’s role as an RTO?**

22 **A.** PJM was formed in 1927 by Public Service Electric and Gas, Philadelphia
23 Electric and Pennsylvania Power and Light Companies in order to share resources

1 for the purposes of increasing reliability and gaining economic benefits. The
2 concept of operating the combined electric systems as though they were a single
3 system led PJM to be called the “Pioneer Power Pool”. In 1956, the PJM
4 Agreement was put into place, and Baltimore Gas and Electric and GPU Services
5 Companies joined. Later, Potomac Electric Power, Atlantic City Electric and
6 Delmarva Power and Light Companies also joined PJM. For nearly 70 years,
7 PJM reliably operated and provided for coordinated planning of the transmission
8 systems of its members. Considerable benefits accrued to the PJM members and
9 their customers through PJM’s centralized security-constrained economic
10 dispatch, reserve requirements and coordinated planning. The PJM 500 kV
11 backbone transmission system was mainly a series of jointly planned and financed
12 projects. Recognizing the changing regulatory landscape resulting from the
13 Energy Policy Act of 1992, PJM and its members began to change the structure of
14 PJM. In 1997, FERC accepted the PJM Operating Agreement, Tariff and
15 attendant documents, and an independent PJM Board of Managers was elected.
16 Since then, PJM membership and territory has increased significantly and its roles
17 as an RTO have likewise grown.

18 **Q. What benefits do members derive from belonging to PJM?**

19 **A.** PJM continues to operate and plan the transmission system as though it were a
20 single system. Corporate and state boundaries are not considered when taking
21 operational action or making planning decisions. The impact of specific elements
22 of PJM’s role as an RTO is estimated to produce as much as \$2.3 billion per year

1 in benefits and economic value for the region PJM serves. These elements are
2 discussed below.

3 **Reliability Savings**

4 PJM's ability to direct changes in the output of generating resources rather than
5 curtail power-sales transactions to deal with transmission congestion enables it to
6 deal with transmission constraints more rapidly and effectively.

7 By planning for future reliability needs on a region-wide rather than a
8 utility-by-utility or state-by-state basis, PJM's RTEP process helps focus on
9 transmission upgrades that meet reliability criteria and increase economic
10 efficiency.

11 **Generation Investment Savings**

12 The large size of the PJM market area, combined with its diversity of demand and
13 resources, reduces the overall level of capacity needed to ensure adequate reserves
14 of electricity to meet peak demand or emergency situations. This capacity buffer,
15 known as the reserve margin, would need to be higher without the PJM RTO.
16 Consumers avoid the costs of additional generation to meet higher levels of
17 reserves.

18 The commitment of demand-response resources to reduce load during
19 system peaks also forestalls the cost of building additional generating facilities.
20 Through the Reliability Pricing Model ("RPM"), demand response competes on
21 an equal footing with generation and transmission in the capacity market.
22 Through RPM, the quantity of demand response that is providing capacity has

1 increased by over 1,800 MW, reducing the amount of generating capacity that is
2 required by that same amount.

3 **Energy Production Cost Savings**

4 PJM's centralized dispatch of numerous resources over its expanded territory
5 produces significant efficiencies and cost savings compared with the previous
6 operation of independent control areas across the region. The increasing
7 effectiveness of PJM's dispatch operations also has reduced operating reserve
8 costs.

9 **Grid Services Savings**

10 By operating markets for grid services, also known as ancillary services, across its
11 footprint, PJM achieves economies in providing services that are essential to the
12 reliability of the electric system. Synchronized reserve service supplies electricity
13 if the grid has an unexpected need for more power on short notice, while
14 regulation helps match generation and load by correcting short-term changes in
15 electricity use that might affect system stability.

16 **Q. How does planning the transmission system fit into PJM's role?**

17 **A.** As part of its ongoing responsibilities as an RTO, PJM prepares the RTEP each
18 year in order to analyze the electric supply needs of the customers in the PJM
19 region. PJM evaluates the aggregate needs across its system, identifying potential
20 problems on both a local and regional level. Reliability problems are blind to the
21 boundaries of states or transmission owner service territories. By identifying
22 problems on a regional basis, PJM is able to identify the most effective regional
23 solutions that ignore state and transmission owner boundaries. The RTEP directs

1 transmission upgrades to address near-term needs within five years and assesses
2 long-lead-time transmission options requiring a planning horizon of 15 years or
3 more. The RTEP provides forward-looking information as to the state of the
4 supply and delivery infrastructure and identifies future system needs, both in
5 terms of reliability and market efficiency. The RTEP will direct PJM's
6 transmission owning members to address such needs through specific
7 transmission solutions. However, the information publicly disseminated through
8 the RTEP permits other resource providers, including generators, demand
9 response providers and merchant transmission owners, the opportunity to address
10 identified system needs in a manner that might delay or even obviate the
11 transmission solution first identified in the RTEP.

12 **Q. Are PSE&G and PPL Electric Utilities (“PPL Electric”) PJM members?**

13 **A.** Yes. PSE&G and PPL Electric are members of PJM and each is considered a
14 “Transmission Owner” under the Operating Agreement.

15 **Q. How is the term “TRANSMISSION OWNER” defined by the Operating**
16 **Agreement?**

17 **A.** “Transmission Owner” means a PJM member that owns Transmission Facilities
18 or leases Transmission Facilities with rights equivalent to ownership.
19 “Transmission Facilities” means facilities that (i) are within the PJM region, (ii)
20 meet the definition of transmission facilities pursuant to FERC’s Uniform System
21 of Accounts or have been classified as transmission facilities in a ruling by FERC
22 addressing such facilities, and (iii) have been demonstrated to the satisfaction of
23 PJM to be integrated with the PJM transmission system and integrated into the

1 planning and operation of the PJM transmission system to serve all of the power
2 and transmission customers within the PJM region.

3 **Q. Does PJM coordinate transmission planning with neighboring systems?**

4 **A.** Yes. PJM coordinates its planning processes with neighboring systems to
5 address issues of mutual concern. These coordinated planning efforts evaluate,
6 first, the reliability of the interconnected grid and, second, the efficiency and
7 economic performance of the grid. PJM participates in such interregional
8 planning under arrangements with the Midwest Independent Transmission
9 System Operator, the Independent System Operator of New England, the New
10 York Independent System Operator, the Tennessee Valley Authority, Progress
11 Energy and Duke Energy.

12 **Q. Does the RTEP process involve others outside of the PJM organization?**

13 **A.** Yes. The RTEP process is open, transparent and collaborative from start to
14 finish. Forums and processes provide opportunities for stakeholders to help PJM
15 improve the transmission grid ensuring reliability and access to robust,
16 competitive markets. The activities of the Transmission Expansion Advisory
17 Committee (“TEAC”) and the Sub-regional RTEP Committees provide the
18 primary forum for the ongoing exchange of ideas, discussion of issues and
19 presentation of planning findings. PJM governing committees, such as its
20 Members Committee, Planning Committee and Transmission Owners Agreement
21 Administrative Committee, also provide additional opportunities for stakeholder
22 input.

1 **Q. Please describe the relationship of the TEAC and the sub-regional**
2 **committees to the RTEP process.**

3 **A.** The TEAC operates under specific provisions of the Operating Agreement.
4 TEAC activities are at the core of stakeholder input in the RTEP process. The
5 scope of the TEAC's responsibility includes the review of and the provision of
6 comments and input on the following:

- 7 • Scope and assumptions of RTEP studies, including economic/market
8 efficiency analysis;
- 9 • RTEP analysis at defined points during the RTEP process cycle;
- 10 • RTEP recommendations to be proposed to the PJM Board for
11 endorsement; and
- 12 • Specified RTEP process matters as requested by the PJM Board.

13 TEAC participation is open to all transmission customers, any other entity
14 proposing to provide transmission facilities to be integrated into the PJM region,
15 all PJM members, representatives of state commissions, the agencies and offices
16 of state consumer advocates of states in the PJM region and any other interested
17 parties. This broad group of constituents fosters a wide range of opinions,
18 comments and advice on RTEP process plan development and recommendations
19 for PJM Board approval.

20 Following the presentation of analysis assumptions or results to the
21 TEAC, stakeholders are invited to provide written comments. These comments
22 are provided to the PJM Board for their consideration and serve as the basis for
23 on-going dialogue at subsequent TEAC meetings.

1 The Sub-Regional RTEP Committees are similarly defined in the
2 Operating Agreement and provide for a more localized review of lower voltage
3 RTEP projects as well as the local plans of the individual transmission owners.
4 Participation in the Sub-Regional RTEP Committees is open to the same entities
5 that may participate in the TEAC process. Sub-Regional RTEP Committees are
6 currently established for the Mid-Atlantic, South, and West sub-regions of PJM.

7 **Q. What is the basis for PJM’s authority to carry out its responsibilities?**

8 **A.** As a FERC-approved RTO, PJM is responsible to ensure the reliability of the
9 transmission grid in the entire 13-state PJM territory. PJM’s authority with
10 respect to its planning process is based on its role as an RTO, approved by FERC,
11 and the PJM Agreements which have been filed at and approved by FERC. In
12 addition, FERC has approved the NERC Reliability Standards to which PJM
13 plans and operates. Among other functions, PJM is designated by NERC as the
14 Planning Authority and the Transmission Planner with respect to compliance with
15 the NERC standards. PJM applies reliability criteria to evaluate transmission
16 system conditions and then develops the transmission solutions needed to ensure
17 compliance with NERC Reliability Standards. Thus, the authority for PJM to
18 carry out its responsibilities is established by FERC’s approval of the PJM
19 Agreements and the NERC Reliability Standards and PJM’s designated roles with
20 respect to those standards.

1 **Q. What are PJM'S overall responsibilities with respect to maintaining**
2 **reliability?**

3 **A.** As an RTO, PJM is charged with ensuring the safety, reliability and security of
4 the Bulk Electric System. It manages and controls the real-time operation of the
5 power grid and it provides for comprehensive regional transmission expansion
6 planning. This planning function assesses the grid 15 years into the future and
7 directs enhancements to ensure that reliability is preserved into the future,
8 recognizing the long lead times required to build transmission infrastructure. PJM
9 is also responsible for administering a number of wholesale markets including:
10 day-ahead and real-time energy markets, Reliability Pricing Model ("RPM")
11 Auction, Financial Transmission Rights auction, and Regulation, Spinning
12 Reserve, Black Start Service and Reactive Supply Ancillary Services markets.

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14 **IV. PJM TRANSMISSION PLANNING PROCESS**

15 **Q. Does PJM have a written protocol for its transmission planning process?**

16 **A.** Yes. PJM's role in transmission planning is set forth in Schedule 6 of the
17 Operating Agreement, entitled "Regional Transmission Expansion Planning
18 Protocol." The purpose and objective of Schedule 6 is stated as:

19 This Regional Transmission Expansion Planning Protocol shall
20 govern the process by which the Members shall rely upon the
21 Office of the Interconnection to prepare a plan for the
22 enhancement and expansion of the Transmission Facilities in
23 order to meet the demands for firm transmission service, and to
24 support competition, in the PJM Region. The Regional
25 Transmission Expansion Plan (also referred to as "RTEP") to be
26 developed shall enable the transmission needs in the PJM Region
27 to be met on a reliable, economic and environmentally acceptable
28 basis.

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This protocol goes on to describe the requirements for the RTEP to conform with NERC and other applicable reliability criteria, the committee structure to be put in place to provide for stakeholder participation in the development of the RTEP, the contents of the RTEP, the procedures used to develop the RTEP, the process of approval of the RTEP by the PJM Board, the obligation on the part of the transmission owners to build upgrades included in the RTEP, and the treatment of interregional transmission upgrades. The planning process is further described in extensive detail in the PJM Manuals.

Q. Describe the primary elements of PJM’S planning process.

A. The RTEP process integrates transmission, generation and demand-side resources to address transmission system constraints involving reliability and persistent congestion. The result is one process that integrates many system factors, including:

- Forecasted load growth, demand-side-response efforts and distributed generation additions;
- Interconnection requests by developers of new generating resources and merchant transmission facilities;
- Solutions to mitigate persistent congestion and forward-looking economic constraints and to ensure adequate allocation and funding of long-term financial transmission rights;
- Assessments of the potential risk of aging infrastructure;
- Long-term firm transmission service requests;
- Generation retirements and other deactivations;

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- Transmission Owner-initiated improvements; and
- Load-serving entity capacity plans.

A transmission owner’s integration into PJM has the potential to enhance reliability and economic benefits as a result of inclusion in a larger, stronger and more diversified portfolio of aggregated resources. In order to realize this mutual benefit for its members, PJM plans the integrated system from a regional perspective in collaboration with each individual transmission owner. PJM’s authority and obligation to perform this function is established in its Tariff and related agreements whereby certain planning functions that historically had been managed by individual transmission owners have been contractually assigned to PJM. This collaborative planning process - the RTEP process - provides an open and inclusive forum for participation by all classes of market participants and stakeholders. Coordinated planning among transmission owners is not new to PJM since its establishment as an RTO. Significant portions of the eastern-PJM 500 kV transmission system were developed as joint projects among groups of two or more transmission owners to meet their collective needs. Other portions were developed by individual transmission owners to meet their own needs. Regardless of the manner of development of each backbone line, customers in Pennsylvania and New Jersey benefit from lines built in Maryland and Virginia, and vice versa. In PJM’s current role, it is able to evaluate broad regional needs and identify the most effective regional solutions, ignoring boundaries between states and transmission owner service territories.

1 **Q. What is a “load-serving entity”?**

2 **A.** Under the Operating Agreement, a load-serving entity means an entity that serves
3 end-users (or ultimate consumers of electricity) within the PJM region and that
4 has been granted authority or has an obligation pursuant to state or local law,
5 regulation or franchise to sell electric energy to end-users located within the PJM
6 region. The term includes load aggregators, power marketers and duly
7 designated agents of load-serving entities.

8 **Q. Are the transmission owners actively involved in the PJM RTEP process**
9 **with the selection of the expansion plans?**

10 **A.** Yes. Transmission Owner involvement is essential to make the process work.
11 The participation of the Transmission Owners’ planning groups is extremely
12 important in the development of the regional transmission plan. The
13 Transmission Owners have first-hand knowledge of their systems and have
14 developed relationships with load-serving entities within their area of PJM.
15 When PJM determines there are reliability violations, the Transmission Owners
16 are consulted to validate the violation and to suggest recommended upgrades to
17 relieve them. Additionally, each Transmission Owner performs its own
18 independent analysis to identify reliability violations from a more local zone
19 perspective. This approach leads to a more comprehensive package of upgrades
20 that incorporates resolutions to both local and regional reliability violations.

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1 **Q. Describe the nature and extent of the RTEP projects ordered by the PJM**
2 **Board.**

3 **A.** More than \$13.2 billion of transmission upgrades and additions, representing over
4 1400 distinct transmission projects ranging from 69 kV to 765 kV, have been
5 authorized by the PJM Board from the inception of the RTEP process in 1999
6 through December 2008. About \$11.3 billion of baseline transmission network
7 upgrades across PJM ensure that established reliability criteria will continue to be
8 met. At the same time, \$1.9 billion of additional transmission upgrades will
9 enable the interconnection of more than 45,000 MW of new generating resources
10 and merchant transmission projects.

11 In June 2006, the PJM Board approved the 502 Junction – Loudoun line,
12 referred to as the TrAIL project. In June 2007, the PJM Board approved two new
13 backbone transmission network facilities, the Amos – Kemptown line (the PATH
14 project) and the Susquehanna – Roseland Project. In October 2007, they approved
15 one additional backbone transmission facility, the Possum Point – Calvert Cliffs –
16 Indian River – Salem line (the MAPP project). Taken together, these four
17 projects will substantially enhance the reliability and economic performance of
18 the transmission system in the Mid-Atlantic region of PJM, which includes all of
19 the state of New Jersey and a large portion of the state of Pennsylvania. They also
20 approved approximately 40 additional transmission enhancement projects in 2007
21 which were required due to reliability violations caused by baseline load
22 growth/deliverability and reliability, generation interconnection/deactivation and
23 merchant transmission interconnection.

1 In 2008, the PJM Board approved 450 additional transmission projects,
2 valued at about \$3.4 billion, due to transmission system criteria violations.

3 **Q. Describe what you mean by “Baseline Transmission Network Upgrades.”**

4 **A.** PJM’s baseline reliability assessments identify areas where the electric power
5 system, as forecasted over a specific time, is not in compliance with NERC
6 Reliability Standards and PJM reliability criteria. These baseline assessment
7 analyses lead to recommendations for enhancement plans, referred to as baseline
8 transmission network upgrades, to ensure compliance with each set of standards.
9 The PJM system, including those baseline transmission network upgrades, is
10 compliant with all applicable Reliability Standards and criteria and serves as a
11 baseline for the analysis of subsequent requests for transmission service and
12 interconnection.

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14 **V. ROLE OF FERC AND NERC**

15 **Q. Please explain the role of FERC and NERC in addressing transmission**
16 **reliability.**

17 **A.** Historically, compliance with Reliability Standards developed by NERC was
18 considered voluntary. Because those standards set an industry standard for good
19 utility practice, compliance was generally universal by Transmission Owners and
20 generation owners. The Energy Policy Act of 2005 (“EPAct 2005”) established
21 a mandatory compliance and enforcement regime for Reliability Standards under
22 the oversight of FERC. Pursuant to EPAct 2005, FERC has designated NERC as
23 the “Electric Reliability Organization” for the United States and NERC has

1 proposed various Reliability Standards, most of which have been adopted by
2 FERC. Mandatory compliance with NERC Reliability Standards began on
3 June 1, 2007. PJM has been applying the FERC-approved NERC Reliability
4 Standards, and the PJM deliverability criteria used to apply them, on a mandatory
5 basis since the initiation of the RTEP process. Failure to comply with the FERC-
6 approved Reliability Standards may result in penalties as high as \$1 million per
7 violation per day.

8 **Q. What reliability criteria does PJM evaluate in the development of the RTEP?**

9 **A.** PJM has developed and utilizes a wide range of reliability criteria in the
10 development of the RTEP. PJM performs tests to determine if the transmission
11 system meets that criteria. If a violation is found, PJM develops a solution to that
12 violation to ensure the continued reliability of the transmission system in the
13 future. All reliability criteria testing procedures employed in the development of
14 the RTEP include detailed assumptions regarding load levels, transfer levels and
15 generation patterns. The tests are referred to as “bright line” tests because there
16 can be no doubt as to whether the criteria are satisfied or violated. In Mr.
17 McGlynn’s testimony, he describes PJM’s load deliverability and generator
18 deliverability tests, and how PJM applies these tests to determine compliance with
19 NERC Reliability Standards.

20 **Q. Please explain what happens when PJM identifies transmission system
21 reliability violations through the RTEP process.**

22 **A.** If PJM identifies NERC Standards violations through the RTEP process, the
23 NERC Standards require that solutions be developed and implemented to mitigate

1 those violations. This was the outcome of the 2007 and 2008 RTEP processes
2 and is the fundamental reason for PJM’s direction to PSE&G and PPL Electric to
3 undertake transmission reinforcements. Several projects, including the
4 Susquehanna – Roseland Project, were approved by the PJM Board to address the
5 violations identified through the RTEP. In other words, the Susquehanna –
6 Roseland Project application is the result of PJM’s Federally-mandated efforts as
7 an RTO to identify and attempt to resolve transmission reliability issues within its
8 control area.

9 **Q. How are reliability projects built and paid for?**

10 **A.** PJM’s Consolidated Transmission Owners Agreement (“TOA”) requires
11 Transmission Owners to build transmission facilities, approved by the PJM
12 Board, that are needed to meet Reliability Standards. Regardless of who bears
13 responsibility for the actual construction of new transmission facilities, pursuant
14 to Schedule 6 of the Operating Agreement, the cost of new reliability facilities is
15 paid for by load-serving entities in transmission zones that cause the need for the
16 project or those entities identified as beneficiaries of the project. Recognizing the
17 broad-reaching regional benefits of backbone transmission systems, FERC has
18 mandated that the costs for baseline facilities at or above the 500kV voltage level
19 are allocated among the transmission zones in proportion to their load ratio share
20 at the time of each zone’s annual peak of the previous year ending October 31.
21 For example, the PPL Electric and PSE&G transmission zones are currently
22 allocated 5.37% and 7.61%, respectively, of the cost of projects such as the

1 Susquehanna – Roseland Project. Transmission Owners recover their costs
2 through FERC-approved transmission service rates.

3 PJM monitors and coordinates the construction of all new transmission
4 facilities. Projects associated with the interconnection of new generation and
5 merchant transmission projects must meet specified financial and construction-
6 related obligations. These requirements enable PJM to ensure that upgrade
7 construction remains on schedule and required in-service dates are met.

8 **Q. Please explain the significance of PJM’S five year baseline RTEP analysis.**

9 **A.** PJM performs a five-year baseline analysis to assess compliance with reliability
10 criteria and recommend transmission upgrades to meet near-term demand growth
11 for customers’ electricity needs not only from existing generation, but from new
12 resources that arise from interconnection requests by developers seeking to
13 construct new generating plants and merchant transmission facilities. The five-
14 year baseline component of PJM’s RTEP process includes the following:

- 15 • Solutions to address baseline transmission constraints revealed by
16 reliability criteria violations observed in power-flow and related studies;
- 17 • Cost responsibility allocations for baseline reliability upgrades;
- 18 • “Direct connection” transmission enhancements associated with
19 generation and merchant transmission interconnection requests; and
- 20 • Necessary “network” transmission enhancements in response to
21 interconnection requests, i.e. new transmission facilities or upgrades to
22 existing transmission facilities beyond the point of interconnection.

1 Approved transmission upgrades identified through the five-year planning process
2 have ensured continuing compliance with all applicable reliability criteria and
3 have enabled the interconnection of more than 22,000 MW of new generation to
4 the grid.

5 **Q. Does PJM engage in planning beyond a five year horizon?**

6 **A.** Yes. The development of the five-year baseline plan is only the first step in a
7 comprehensive 15-year planning process. PJM's 15-year planning horizon
8 permits the consideration of many long-lead-time transmission options. This
9 type of planning enables PJM to address both the reliability and economic
10 performance of the transmission grid based on the impacts of long-term load
11 growth and a wide range of market factors. The process allows transmission
12 projects to be developed that resolve longer-term reliability needs, but placed in
13 service earlier than would have been required based on those reliability needs if
14 the associated costs are justified by the benefits derived through greater
15 efficiency in energy and capacity markets.

16 The scope of 15-year planning encompasses reliability-based sensitivity
17 analyses. These sensitivity studies examine the long-term reliability impacts of
18 changes in the regional economy, the extent of loop flows within PJM and
19 assumptions about generation resources.

20 PJM also conducts market efficiency studies as part of each RTEP cycle's
21 15-year analysis. Market efficiency analyses address such factors as the impacts
22 of fuel and emissions-related prices, generation retirements and the delivery needs
23 of the new "clustered" generation projects, such as those emerging in PJM

1 associated with large baseload Midwest and northern Pennsylvania coal projects,
2 nuclear generation in Maryland and northern Virginia, Appalachian Ridge and
3 northern Illinois wind farms and natural gas pipeline access projects. This
4 analysis provides market participants with both historic congestion information
5 and fifteen-year econometric projections of the cost and benefits of proposed
6 transmission projects.

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9 **VI. RTEP RESULTS**

10 **Q. What were the results of this RTEP process in 2007?**

11 **A.** Thirteen separate 500 kV transmission facilities were found to be overloaded in
12 the 2007 RTEP, beginning as early as 2012. In addition, 23 transmission
13 facilities in Eastern Pennsylvania and New Jersey were found to be overloaded
14 beginning as early as 2013. In June and October 2007, the PJM Board formally
15 approved three additional backbone transmission facilities as a result of the 2007
16 RTEP analysis and findings. As discussed earlier, these three backbone projects
17 were the PATH line, the Susquehanna – Roseland Project, and the MAPP line,
18 which were included in the RTEP to resolve future reliability impacting the entire
19 PJM Mid-Atlantic region, including all of the state of New Jersey and a
20 significant portion of the state of Pennsylvania. This was the second 15-year
21 analysis and it considered a number of transmission options to resolve reliability
22 criteria violations through 2021 and beyond.

1 Transmission options were considered in some 30 alternative
2 combinations and yielded a number of key conclusions that guided selection of
3 the upgrades submitted to and approved by the Board in 2007. Additional details
4 are presented in Mr. McGlynn's testimony.

5 **Q. Why is PJM'S fifteen year planning horizon important in the context of**
6 **transmission system planning, especially for significant projects?**

7 **A.** A 15-year planning horizon permits the consideration of many long-lead-time
8 transmission options. This type of planning addresses the system reliability
9 impacts associated with long-term load growth, the impacts of generation
10 retirements and the delivery needs of clustered generation projects. These
11 clusters are associated with large base load coal projects in the Midwest and
12 central Pennsylvania; nuclear generation in Maryland, Virginia and central
13 Pennsylvania; Appalachian Ridge and northern Midwest wind farms and natural
14 gas pipeline access projects throughout PJM. The 15-year planning process also
15 allows for the integration of developing solution options, including alternate
16 sources of energy, such as wind, smart grid technology, and conservation
17 programs implemented through state energy plans.

18 Imbalances between local supply and demand – the result of load growth,
19 lagging generation additions and generation retirements – continue to require
20 progressively more transmission upgrades. PJM's RTEP studies have revealed
21 that load growth and the location of new generating facilities will impose
22 increasingly heavy levels of west-to-east power flows across PJM's regional,
23 interstate transmission system.

1 The PJM transmission system is rapidly reaching the point where short-
2 term, incremental fixes will no longer be sufficient to mitigate identified
3 reliability criteria violations. New high-voltage transmission must be
4 constructed to maintain reliable operations and to grow robust energy markets for
5 the benefit of all customers. Thus, because of the lead times associated with the
6 strong interstate backbone transmission projects the PJM region now needs, the
7 planning, siting and construction of these facilities must begin now. One of the
8 primary drivers for extending the PJM planning horizon to 15 years was the
9 recognition by PJM and its stakeholders that the need for major new transmission
10 capability must be identified in time for construction to be completed before
11 reliability suffers.

12 **Q. Is PJM'S fifteen year planning horizon considered in determining the need**
13 **for the Susquehanna-Roseland Project?**

14 **A.** Yes. Mr. McGlynn's testimony explains that although a number of important
15 violations are expected to occur in 2012, other important violations are projected
16 for subsequent years. Taken together, these violations constitute the justification
17 for the construction of the Susquehanna-Roseland Project.

18 **Q. Does NERC require analysis for periods beyond 5 years?**

19 **A.** Yes. NERC Reliability Standards require that PJM conduct transmission system
20 performance evaluations annually for both near-term (years 1 through 5) and
21 longer term (years 6 through 10) planning horizons.

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VII. CHANGES TO PLANNING ASSUMPTIONS OVER TIME

Q. How does PJM take into account changes in the assumptions used in its planning process over time?

A. Planning is a dynamic process and system conditions change over time. Changing circumstances may result in the need to adjust the assumptions used in planning studies and to re-evaluate decisions made as a result of previous planning analyses. For this reason, PJM tracks changes to these assumptions and the planning process provides opportunities for past planning decisions to be adjusted as required. Each year, during the RTEP process, PJM reviews the transmission plans developed in earlier years to determine whether, as a result of changing assumptions, previously approved transmission upgrades are still required and, if required, whether they are still required in the year originally identified. This process is called a “retool” and is the means PJM uses to ensure the planning process reflects the most current conditions as effectively as possible. Faced with changing system conditions, if the timing and nature of future criteria violations and the progress of construction of previously identified transmission upgrades allow, such upgrades may need to be accelerated or may be deferred or even eliminated and the transmission plan will be adjusted accordingly.

1 **Q. Have conditions continued to change since the completion of the 2007 RTEP**
2 **analysis that provided the justification for the Susquehanna-Roseland**
3 **Project?**

4 **A.** Yes. As I've mentioned, the RTEP process is very dynamic. System conditions
5 and, therefore, study assumptions are continually changing. Since the approval of
6 the Susquehanna-Roseland Project by the PJM Board in June 2007, PJM has
7 integrated a number of changes into the RTEP analyses. For example,

- 8 • a new load forecast was issued in January 2008,
- 9 • several generation projects have progressed through the interconnection
10 process and have signed Interconnection Service Agreements ("ISA"),
- 11 • several units which had previously announced that they would be retired
12 are now expected to return to service,
- 13 • a number of generation projects with signed Facilities Study Agreements
14 have withdrawn from the interconnection queue,
- 15 • demand response has increased in certain areas of PJM,
- 16 • significantly, the retirement of the Benning Road and Buzzard Point
17 generators in Washington D.C. was announced and this event was also
18 modeled, and
- 19 • lastly, a merchant transmission project delivering capacity and energy
20 from New Jersey to New York City has proceeded to the point of
21 executing a Facilities Study Agreement and must also be included in on-
22 going RTEP analysis.

1 Some of these factors have a direct impact on reliability criteria violations related
2 to the need for the Susquehanna - Roseland Project. Even when these changes are
3 taken into account, the results of on-going PJM's RTEP analyses confirm that the
4 Susquehanna - Roseland Project is still required.

5 **Q. Are changes likely to continue to occur after the completion of the 2008**
6 **RTEP?**

7 **A.** Yes. New load forecasts are developed every year. The most recent econometric
8 forecasts suggest that the 2009 Load Forecast Report will project slower load
9 growth rates than seen in earlier forecasts. In addition to changes in load growth
10 rates, new demand response and efficiency programs are likely to be developed
11 and implemented. New generating resources will likely proceed to a point in their
12 development that they should be considered in subsequent analyses and other
13 generating resources will retire and be removed from service. Similarly, a
14 number of merchant transmission projects are under development that may
15 potentially result in withdrawals of generating capacity and energy from the PJM
16 system. All of these factors will impact the needs that have been previously
17 identified through the RTEP, some positively and some negatively.

18 **Q. How will these changes impact the need for the Susquehanna-Roseland**
19 **Project?**

20 **A.** It is likely that supplemental analyses will need to be performed in order to
21 quantify these impacts with respect to the timing of the need for the Project.
22 Many factors, in addition to the load forecast, must be considered to make a
23 determination. As I have discussed, one feature of the RTEP process is the

1 continual re-evaluation of past planning decisions based on changing
2 circumstances. If the timing and nature of future criteria violations changes,
3 previously approved transmission projects may need to be accelerated or deferred
4 and the transmission plan will be adjusted accordingly.

5 **Q. Is it prudent to move forward with a project of this magnitude in the face of**
6 **such uncertainty?**

7 **A.** Yes, it is. As I mentioned above, the PJM transmission system is rapidly reaching
8 the point where short-term, incremental fixes will no longer be sufficient to
9 mitigate identified reliability criteria violations. The violations identified in the
10 RTEP manifest themselves today as persistent transmission congestion and
11 increasing energy and capacity costs to customers in PJM. The consequences of
12 unresolved reliability criteria violations include degraded electric service to
13 customers and a greatly increased risk that customers load will need to be
14 curtailed in order to forestall uncontrolled system blackouts. PJM and
15 transmission owner system operators have a range of emergency procedures at
16 their disposal with which to manage operating circumstances involving the
17 potential for overloaded transmission facilities or unacceptable transmission
18 system voltages. However, these operating procedures include the need to curtail
19 service to demand response customers, to reduce transmission system voltage
20 (referred to as a “brown-out”), and to implement rolling blackouts for network
21 transmission service customers. Backbone transmission facilities, such as the
22 Susquehanna – Roseland Project, can take 4 to 5 years from the filing of required
23 regulatory documents through the completion of construction. Planning for the

1 long term brings with it the need to move forward even though changes may arise
2 during the development and construction phases of a project. What is important
3 to remember is that the operators of the grid should not be provided with a
4 transmission system which must operate on a “knife edge” of reliability for any
5 length of time.

6 **Q. Explain the NERC requirement to act upon violations found during the**
7 **planning process.**

8 **A.** PJM is required to apply NERC Reliability Standards to its planning process. The
9 FERC established this requirement in 1999 in its Order No. 2000. PJM has
10 developed a number of specific reliability criteria and the protocols necessary to
11 test the transmission system against these criteria to ensure transmission system
12 reliability. The NERC Reliability Standards specify a wide range of reliability
13 tests that must be applied over both short (years one to five) and long-term (years
14 six to ten) planning horizons. If PJM identifies criteria violations, then NERC
15 Reliability Standards require that solutions be developed and implemented to
16 mitigate those violations. These solutions must include a schedule for
17 implementation, including expected in-service dates and considering lead times.
18 Subsequent annual assessments must review the continuing need for the identified
19 system facilities. The Susquehanna-Roseland application is the result of PJM’s
20 federally-mandated efforts as an RTO to identify and attempt to resolve
21 transmission reliability issues within its control area.

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1 **VIII. ALTERNATIVES CONSIDERED**

2 **Q. What alternatives were considered prior to selecting the Susquehanna-**
3 **Roseland solution?**

4 **A.** Several transmission alternatives were evaluated prior to selecting the
5 Susquehanna – Roseland Project. These alternatives included:

- 6 • Bossards - Jefferson - Roseland 500 kV
- 7 • Stanton – Roseland 230 kV

8 PJM evaluated each of these alternatives to determine the amount of
9 increased transfer capability each provides and the impact of each on the loading
10 of the 23 key transmission facilities in Eastern Pennsylvania and New Jersey
11 which were identified as reliability criteria violations. PJM chose the
12 Susquehanna - Roseland Project because it had the greatest positive impact on
13 these line loadings throughout the 15-year planning horizon.

14 **Q. What non-transmission alternatives did PJM consider?**

15 **A.** Potential non-transmission solutions included market-driven additions of new
16 generation capacity and demand side management resources located in the eastern
17 part of PJM (Eastern Pennsylvania, Eastern Maryland, Delaware and New
18 Jersey). However, PJM considers it unlikely that sufficient amounts of either can
19 be implemented in these densely developed metropolitan areas to offset entirely
20 the need for additional backbone transmission capability. The slow recent pace of
21 net additions of generation capacity in this area, particularly when considered
22 together with increasingly strict environmental restrictions and increasingly
23 contentious local opposition to siting of such facilities, makes it highly unlikely

1 that the need for the addition of new, high-voltage transmission capability could
2 be avoided through additional generation capacity in the vicinity of the load
3 centers of eastern PJM.

4 Demand side measures similarly cannot realistically be expected to
5 substitute for new bulk transmission capability to serve customers in Eastern PJM.
6 When dealing with complex interregional electric systems, demand response
7 estimates must be realistic to ensure that system reliability is maintained. Unlike
8 a generator, demand response is not expected to provide steady firm capacity
9 output over an extended period of time.

10 Accordingly, for purposes of long-term planning for total system
11 adequacy, substituting demand response for incremental transmission capability
12 could require several times the equivalent amount of new generation that would
13 be needed to offset the new transmission capacity. Demand response does not
14 produce a steady stream of MW equivalent output because it is normally cycled
15 over a given time period (i.e., load would be switched off and on to ensure
16 minimal impact to the demand response provider, rather than switched off for the
17 entire duration of the system need). Also, demand response is produced in a
18 variety of diverse programs, which also result in varied measurements.

1 **Q. You have indicated that PJM does not have the power to compel**
2 **“Alternative” solutions. Please explain what PJM is authorized to do and not**
3 **do in this regard.**

4 **A.** As an RTO, PJM has a defined role in the deregulated electric industry. Its
5 primary transmission-related responsibility is to ensure the reliability of the bulk
6 power transmission system. Although PJM has a number of important tools at its
7 disposal – including the ability to direct transmission owners to construct
8 transmission system reinforcements – its powers are not plenary. PJM is not able
9 to direct or otherwise control the siting, capacity, or timing of new generation in
10 high-load areas. PJM is not able to compel or otherwise control the design and
11 implementation of demand side management (“DSM”) efforts that might, if
12 properly placed and of sufficient dimension, delay or defer the need for
13 transmission reinforcements. PJM can only direct the reinforcement of
14 transmission facilities to address reliability violations, either through the
15 modification of existing transmission facilities (which PJM quite frequently
16 directs) or the construction of new transmission facilities.

17 **Q. Are you suggesting that PJM does not consider non-transmission alternatives**
18 **in evaluating the need for transmission reinforcements?**

19 **A.** Absolutely not. PJM’s planning processes recognize that many of the generation-
20 based and DSM-based alternatives, if targeted, verifiable, and implemented on
21 time and in the right areas of the PJM Region, address identified system reliability
22 issues. As I mentioned above, PJM has a very specifically defined role. Because
23 the consequences of reliability criteria violations can be severe, PJM’s mandate

1 first is to maintain system reliability. That being said, however, PJM's planning
2 process is expressly designed to be responsive to solutions developed through the
3 marketplace, as well as transmission solutions, and the resulting plan is reviewed
4 each year to integrate the on going development of those solution options.

5 **Q. Why is PJM's role so specifically defined and why is PJM empowered only to**
6 **plan and compel transmission solutions?**

7 **A.** Consistent with its FERC approved tariffs, PJM, as an RTO, was delegated
8 planning responsibilities for the transmission system within PJM, as well as the
9 responsibility for the reliable interconnection of generation resources.

10 Initially, FERC's issuance in 1996 of Order No. 888 recognized that larger
11 regional organizations could operate more efficiently and economically. In Order
12 No. 888, FERC initially determined that an ISO must have primary responsibility
13 for the short-term reliability of grid operations, including planning and oversight
14 of maintenance of transmission facilities under its control. The concept
15 developed further, and FERC's Final Rule on RTOs, Order No. 2000, was issued
16 in December 1999, representing the next step in the evolution of PJM's planning
17 processes. Order No. 2000 created the RTO concept and established the rules and
18 functions for them. Order No. 2000 also required public utilities to make
19 appropriate filings with FERC to initiate the process to place their transmission
20 facilities under the control of RTOs. FERC believed there would be widespread
21 competitive advantages resulting from RTOs, including more efficient and
22 effective transmission and generation planning. Order No. 2000 listed seven
23 minimum functions that an RTO must perform. The seventh function is to plan

1 and coordinate necessary transmission additions and upgrades. Also, Order No.
2 2000 required the RTO to perform its functions consistent with the Reliability
3 Standards established by NERC or its successor.

4 PJM and its transmission owners made a joint compliance filing for Order
5 No. 2000 in October 2000, and FERC granted PJM provisional RTO status in July
6 2001. This initial filing included the PJM RTEP, which was subsequently
7 modified pursuant to FERC's 2001 Order. The PJM Operating Agreement, which
8 includes the PJM RTEP process, provides that expansion plans will emerge from
9 a coordinated process involving the transmission owners for the region, and that
10 these plans will be reviewed publicly through the PJM TEAC. Also, PJM's
11 manuals, long term planning, and RTEP process must all conform to NERC
12 standards.

13 Finally, the FERC has vested in PJM the ultimate responsibility for
14 transmission expansion planning in the PJM control area. In order to carry out
15 this responsibility, the FERC authorized PJM to compel the construction of new
16 transmission in order to ensure system reliability. PJM's planning and expansion
17 process was also specifically designed to encourage market-driven operating and
18 investment actions for preventing and relieving congestion. Hence, PJM's
19 authority today is limited to requiring new transmission facilities in accordance
20 with NERC Reliability Standards.

21 **Q. Does PJM conduct "integrated resource planning"?**

22 **A.** Historically, the corporate entities that own transmission infrastructure also
23 controlled a large portion of the existing generation resources. In years gone by,

1 these entities could engage in integrated planning which included both generation
2 and transmission solutions for solving transmission reliability issues. However,
3 FERC has mandated very specific prohibitions with respect to communications
4 between the generation and transmission functions within these corporations.
5 FERC initiated these rules when electric deregulation began in 1992. The
6 prohibition on communications is designed to encourage competition and the
7 development of competitive markets in the energy industry. PJM's role is to
8 solicit a wide variety of possible solutions and then determine if the aggregate of
9 these proposed market-based initiatives will be sufficient to ensure a reliable
10 transmission infrastructure in the future. If not, then PJM is obligated to propose
11 transmission solutions. PJM is not permitted to mandate generation or DSM
12 solutions.

13 PJM's planning process is fully integrated in that it examines all needs
14 with respect to transmission service and all solution options proposed through the
15 market place. To the extent that transmission needs are not satisfied through
16 market-driven solutions, the planning process will specify regulated transmission
17 solutions to fill the gap. PJM's process does not represent "Integrated Resource
18 Planning" in the historical context, in that there is no one decision-maker
19 choosing between solution options, selecting one market-based solution over
20 another, a market-based solution over a regulated solution, or vice versa.

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1 **Q. How are market-based solution options proposed for consideration in the**
2 **development of the RTEP?**

3 **A.** Market-based solutions are developed and integrated into the RTEP process in
4 different ways and can come in the form of generation, merchant transmission,
5 and demand response proposals. Generation and merchant transmission proposals
6 are introduced through the interconnection queue process. Demand response
7 solutions are introduced by participation in RPM auctions.

8 **Q. Under what conditions are generation proposals integrated into the**
9 **development of the RTEP?**

10 **A.** Generation projects must request interconnection to the PJM transmission system
11 through the interconnection queue. The rules governing the interconnection
12 process are laid out in the PJM tariff and the related procedures are described in
13 the PJM Manuals.

14 A series of studies are performed to determine the network transmission
15 upgrades that will be required in order to safely and reliably interconnect the new
16 generator to the PJM grid. The studies, the Feasibility Study, the System Impact
17 Study, and the Facilities Study, are progressively more detailed and provide the
18 generation interconnection customer with increasingly more refined information
19 about the requirements to interconnect and the time and cost required to
20 implement the interconnection.

21 After the completion of the Facilities Study, the interconnection customer
22 is tendered an Interconnection Service Agreement (ISA) and, if required, a
23 Construction Services Agreement (CSA). Once an interconnection customer has

1 executed an ISA the generation project is modeled in all RTEP studies, beginning
2 in the year in which it is expected to be in service, in the same manner as any
3 existing in-service generator. That is, it may contribute to resolve potential
4 reliability criteria violations in planning studies by reducing flow on constrained
5 transmission facilities and it may, likewise, increase flow on constrained
6 transmission facilities, contributing to the possibility that a criteria violation will
7 result. Alternatively, if a generator bids and clears in an RPM auction and takes
8 on a forward commitment to provide service in a future planning year, it is
9 modeled in the same manner as if it had executed an ISA.

10 Prior to the execution of an ISA, a proposed generator is modeled as being
11 in service in situations where it will contribute to increased loading on constrained
12 transmission facilities after it has executed a Facilities Study Agreement.

13 **Q. Why are not all proposed generators considered in the development of the**
14 **RTEP?**

15 **A.** To date, PJM has evaluated requests for the interconnection of over 1,300
16 generation projects totaling over 280,000 MW of generating capacity. Of all of
17 the projects initially proposed, approximately 12% of the MW of those projects
18 eventually are connected to the transmission system and deliver energy into the
19 PJM market. Alternatively, 88% of all proposed MW are never placed into
20 service. This represents a significant level of uncertainty regarding the likelihood
21 that proposed generators will be available in the future to resolve identified
22 reliability criteria violations. The consequences of unresolved reliability criteria
23 violations include degraded electric service to customers and a greatly increased

1 risk that customers load will need to be curtailed in order to forestall uncontrolled
2 system blackouts. Good utility practice requires that proposed generators not be
3 relied upon to resolve reliability criteria violations until a level of certainty is
4 achieved with respect to their being brought into service. PJM uses the execution
5 of the ISA as the indicator that a project is serious and can be expected to be
6 placed into service and, therefore, be available to contribute to the resolution of
7 reliability criteria violations. Even this is not a perfect indicator. While few
8 generation projects withdraw from the interconnection process after executing an
9 ISA, PJM has, to date, seen approximately 23% of the MW associated with
10 executed ISAs withdraw from the interconnection process and fail to be placed in
11 service, and projects constituting about 25% of the MW associated with executed
12 ISAs are currently suspended.

13 **Q. Why are proposed generators with executed Facilities Study Agreements**
14 **included only in situations where they may contribute to the loading on**
15 **constrained facilities and not where they would contribute to the resolution**
16 **of reliability criteria violations?**

17 **A.** While the bulk of the drop-out rate experienced with interconnection projects
18 occurs prior to the execution of Facilities Study Agreements, there are still a
19 noticeable number of projects that withdraw from the queue and are not placed
20 into service. The risk of these withdrawals to system reliability would be too great
21 if the development of the RTEP were to depend on their going into service as a
22 means to resolve future reliability criteria violations. Further, while the deposits
23 provided by interconnection customers are significant, security for required

1 network transmission upgrades is not provided until an ISA is executed. In other
2 words, the interconnection customer does not have sufficient “skin in the game”
3 at the point of executing a Facilities Study Agreement for PJM to risk the future
4 reliability of the grid. However, the development of the RTEP must consider the
5 adverse impact that such projects imposes on the grid so that proposed
6 transmission upgrades meet all expected needs, including the deliverability of the
7 potential new generation project.

8 **Q. Under what conditions are merchant transmission proposals integrated into**
9 **the development of the RTEP?**

10 **A.** As with generation interconnection proposals, after the completion of the
11 Facilities Study, the merchant transmission interconnection customer is tendered
12 an ISA and, if required, a CSA. Once the interconnection customer has executed
13 an ISA the merchant transmission project is modeled in all RTEP studies,
14 beginning in the year in which it is expected to be in service. That is, it may
15 contribute to resolve potential reliability criteria violations in planning studies by
16 reducing flow on constrained transmission facilities and it may, likewise, increase
17 flow on constrained transmission facilities, contributing to the possibility that a
18 criteria violation will result.

19 After a merchant transmission project has executed a Facilities Study
20 Agreement but prior to its execution of an ISA, a proposed merchant transmission
21 project is modeled as being in service in situations where it will contribute to
22 increased loading on constrained transmission facilities.

1 **Q. Under what conditions are demand response programs integrated into the**
2 **development of the RTEP?**

3 **A.** Demand response programs are integrated into the development of the RTEP
4 when they clear in an RPM auction and take on a forward commitment to provide
5 service in a future planning year. Such programs, however, are only modeled in
6 circumstances where they would expect to be enacted in day-to-day operations.
7 Specifically, demand response programs can only be enacted during operational
8 emergency conditions. Accordingly, these programs are modeled during load
9 deliverability testing and only within the area under test. Demand response
10 programs are not modeled in areas not under test nor for tests of other criteria that
11 do not represent operational emergency conditions.

12 **Q. Is the Susquehanna-Roseland Project included in the RTEP for the purpose**
13 **of delivering any specific generators or classes of generation to specific**
14 **groups of PJM customers?**

15 **A.** No. The Susquehanna - Roseland Project was identified to resolve a number of
16 reliability criteria violations. In doing so, the Susquehanna – Roseland Project
17 will enhance the ability of all generating resources in PJM, in aggregate, to be
18 delivered to the aggregate customer load on the PJM system. The Susquehanna –
19 Roseland Project is neither intended to deliver any one specific generating
20 resource or class of generating resources, nor is it designed to promote the future
21 development of any class of new generation. There is currently a wide diversity of
22 fuel types among generation projects in the interconnection queue. Backbone

1 projects, such as the Susquehanna – Roseland Project, will afford customers
2 greater access to all types of new generation.

3 **Q. What are the predominant types of generation currently under development**
4 **in the PJM interconnection queue?**

5 **A.** The bulk of the generation projects in the interconnection queue are wind and
6 natural gas generators. Wind generation currently makes up approximately 47%
7 of the interconnection queue. Natural gas fired generation makes up
8 approximately 35% of the interconnection queue.

9 **Q. Does this conclude your direct testimony?**

10 **A.** Yes, it does.