PJM Regional Transmission Expansion Plan Process

Reliability Scenario Studies Related to the Proposed Clean Power Plan

This analysis provides detailed supplementary information for a report presented to PJM's Transmission Expansion Advisory Committee on July 21, 2105. PJM recognizes the Environmental Protection Agency's final rule will result in changes to some underlying assumptions in the study that will necessitate further analysis.

PJM Interconnection

July 31, 2015

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Contents

Executive Summary

This is the second of two PJM Interconnection studies of the U.S. Environmental Protection Agency's proposed Clean Power Plan requested by the Organization of PJM States, Inc.[1] The first study, an economic analysis, presented potential PJM market impacts, including the identification of fossil-fueled steam generation capacity thought to be at risk for retirement based upon energy market simulation results.[2] This second study uses the results of the economic analysis as the basis for a reliability analysis to determine a range of transmission needs driven by the potential generator retirements under specific scenarios.

The results of both PJM's economic and reliability analyses are not predictions of future outcomes. Rather, they are assessments of possible impacts based on specific assumptions and tempered by uncertainties. Those uncertainties include future market conditions, the form of the final EPA rule and the manner in which states choose to implement the rule.

No one can predict the future with absolute certainty – particularly how something as dynamic and complex as the electric power grid will evolve over the next 10-to-15 years. Numerous factors that drive transmission needs are in motion throughout the proposed CPP compliance period, including the timing of generator retirements and where replacement generation will be located.

Consequently, PJM performed a set of studies to assess reliability implications under several potential CPP retirement scenarios. These scenarios identify potential transmission violations that could occur under a wide range of assumptions. Possible solutions, the time needed to achieve them and their costs are yet to be studied.

Scenario Studies are Snapshots

Historically, generator retirements and the addition of new generation resources happened at a gradual pace. These changes were manageable because of the underlying robustness of the existing grid and sufficient time for any needed transmission to be constructed. Under some CPP scenarios – particularly in the early years of compliance – generators could retire at a faster rate than replacement generation, or the new transmission needed to solve reliability problems, could be built. These scenarios potentially could put a much greater strain on the existing transmission system.

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[1] See OPSI's request posted on www.pjm.com at http://www.pjm.com/~/media/documents/reports/20140905-opsi-data-request-for-section-111d-modeling.ashx

[2] PJM's economic analysis of the proposed Clean Power Plan is posted on PJM.com at http://www.pjm.com/~/media/documents/reports/20150302-pjm-interconnection-economic-analysis-of-the-epa-clean-power-plan-proposal.ashx.

To capture a broad range of potential outcomes, PJM conducted reliability studies based on three levels of at-risk generation: 6 gigawatts, 16 gigawatts and 32 gigawatts. Each level required sufficient generation to serve internal load and firm interchange, as well as maintain an 18 percent reserve margin.

These levels of at-risk generation are derived from PJM's economic modeling of the proposed Clean Power Plan. (See **Appendix A**.) Unlike the economic study results, which show trends over multiple years, reliability scenario studies are static snapshots of a point in time that show the transmission system's ability to handle loads and power flows in the scenarios. PJM conducted several sensitivity analyses to explore variables such as lowering the reserve requirement to 15 percent; assuming heavy reliance on energy efficiency and demand response, and varying the location of replacement generation.

Having Enough Time is Essential

The reliability analysis identifies transmission reliability violations that provide insights into possible transmission solutions that may be necessary to support a set of compliance approaches that states may consider. For example, state plans may require transmission solutions to support the deactivation of existing generators or interconnection of new generation, including renewable resources. The transmission solutions ultimately needed to support state compliance will depend on the EPA's final rule and how each state chooses to implement the rule.

Whenever transmission solutions are considered, one of the most critical factors is the time necessary to identify the need for a transmission solution, to obtain siting approvals and to complete construction – all of which often take years. Generator retirements also present timing challenges. As with the business decisions plant owners faced with the Mercury and Air Toxics Standard (MATS) rule, the CPP rule will prompt owners to consider whether to repower or retire their units. The timing of those decisions and notification of retirement plans to PJM will directly affect the timing and scope of new transmission and the feasibility of completing construction within deadlines.

As with the economic analysis results, reliability analysis results are not predictions of future outcomes. Both analyses needed to use stated assumptions against a backdrop of many moving, interacting parts. Reliability criteria violations and the transmission upgrades needed to resolve them are driven by the amount, location and pace of actual generation deactivations and building the resources to replace the deactivated generation. To perform the reliability assessment, PJM had to make assumptions about the resources that will replace the "at risk" generation resources in order to meet load and reserve margin requirements. Because resource type and siting location impact the reliability analyses, PJM conducted sensitivity analyses around the assumed resource replacement strategies.

Under certain conditions and implementation scenarios and depending on the timing of the many moving parts, new transmission and/or transmission improvements might not be completed in time to maintain reliability. For example, assuming that EPA's rule is finalized in 2015 and that state plans are submitted by the end of 2017, then during the three remaining years until EPA's 2020 interim deadline, the following would need to occur:

1. Generation unit owners' retirement decisions are made and announced.
2. Decisions are made on the development of replacement generation.
3. Reliability criteria violations are identified and transmission solutions developed.
4. Transmission facilities are designed, sited and constructed.

Once the PJM Board approves transmission upgrades, historical experience shows that the pace at which transmission can be completed can range from five years (the Carson-Suffolk 500 kV line) to more than 16 years (the Wyoming-Jackson's Ferry 765 kV line). Moreover, if a number of large-scope transmission projects are required across the United States, the lack of equipment availability could increase lead-time substantially.

PJM's MATS experience suggests that build rates may not ensure that the necessary transmission will be in service before retirements occur. It could depend on the notice given and the aggregate impact of all generation decisions in a given area. For example, roughly 20,000 MW of retirements required $2 billion of transmission upgrades elsewhere. PJM requested that some retiring generation units remain in service beyond their requested retirement dates to ensure reliability in locations where transmission upgrades could not be completed prior to the unit's planned deactivation date. In addition, most MATS-driven transmission enhancements were upgrades to existing facilities, not greenfield transmission projects, which require more time to reach commercial operation. More greenfield transmission projects will be required if replacement resources are not located near the sites where generators retire.

Replacement resources may drive the need for new transmission; if a replacement resource's location and size do not match that of a deactivating resource, a transmission upgrade will likely be required. Overlaying the generator deactivation timeline will be a generator addition timeline, driven by evolving market factors. Essentially, the location and size of both retiring generators and replacement resources will be unknown for some time and will remain a moving target for transmission system changes.

Generation interconnection projects typically enter the queue three to five years before their desired in-service dates. Newly queued generation projects historically have had a low success rate – more than 80 percent of interconnection requests for capacity ultimately withdraw from the queue prior to reaching commercial operation. A successful replacement resource would have to anticipate the retirement of at-risk generators. Otherwise, the grid will face the likelihood of significant delays between the retirement of at-risk generators and the completion of replacement resources. Reliability studies that look more than three years out must hypothesize build rates, locations and fuel sourcing.

Reliability Study Observations

Transmission system reliability studies were designed to identify broad regional impacts that may require long-lead-time projects (at 230 kV and above). PJM offers the following observations based on the reliability studies described in this white paper:

- From a resource adequacy perspective, generation needs could exceed available resources by 2024 in a 32 GW at-risk future scenario in which units retire evenly across each year from 2020 to 2029. If retirements occurred earlier in the 2020-2029 compliance period, resource adequacy needs could exceed resources for a 32 GW scenario by 2022 and by 2028 under a 16 GW at-risk scenario.
- As expected, reliability criteria violations and the attendant need for new transmission were identified in areas where deactivating generators were not replaced with generation in those same locations (such as coal-fired resources that are not replaced with natural-gas-fired plants at brownfield sites that are not also within a short distance of a natural gas pipeline).
- Much depends on the extent to which states themselves rely on renewable resources in their respective individual compliance plans. For example, the EPA renewable portfolio standard reliance assumptions differ from PJM's historical queue experience. It is likely that all the wind-powered facilities that the EPA anticipates to be available will not make it online as shown in the economic analysis. Moreover, historical transmission build-out rates are not likely aggressive enough to meet the EPA's wind penetration rate assumptions.
- The location of replacement generation will drive the need for new transmission. For example, replacement generating resources – such as wind power – likely would locate in the western region of PJM. Additional transmission capability to reach eastern PJM load centers likely would be needed.
- Scenario studies suggest that overloads clustered along specific corridors would require additional review to assess the feasibility of certain types of upgrades. That, in turn, would impact both the cost of solving identified reliability criteria violations and the ability to complete construction of facilities in time to simultaneously comply with the CPP while avoiding those reliability violations.

Resource Neutral

PJM provides this information as an independent source of subject matter expertise. PJM takes no policy position on the EPA's proposed Clean Power Plan. PJM does not advocate particular energy or environmental policies, forecast market outcomes or advocate any replacement strategies driven by them. PJM's primary focus is reliability, followed by the operation of efficient and non-discriminatory electricity markets in which PJM is resource-neutral. PJM does not forecast market outcomes but rather models outcomes based on specific sets of assumptions.

Resource Adequacy Risk

System reliability encompasses resource adequacy and transmission reliability. Resource adequacy examines whether sufficient capacity resources – including reserves – exist to serve load and firm interchange requirements. Transmission reliability assesses the ability to deliver power from the point of generation to the point of consumption within established reliability criteria. Both dimensions are key to understanding the ability of PJM to serve customer load reliably – to keep the lights on.

The first part of the reliability studies examined resource adequacy to assess PJM's ability to serve load and firm interchange with internal generating resource reserves from 2020 through 2029, ignoring, for the moment, transmission limitations.

In order to provide some perspective around the potential timing of resource adequacy issues, **Figure 1** and **Figure 2** attempt to show when PJM could expect resources levels to fall below the target level of peak load plus reserves designed to ensure reliability. Each figure reflects the addition of roughly 3,300 MW per year based on 10 years of PJM queue history. In both figures, the blue diamond line represents PJM load-plus-reserve requirement, its generation requirement. Against this, PJM has plotted three lines in each figure reflecting three generation deactivation scenarios: 6 GW (blue line), 16.5 GW (orange line) and 32 GW (green line).

PJM determined these levels of at-risk generation in its economic modeling of the CPP. (See **Appendix A** for more details.) **Figure 1** assumes a uniform rate of at-risk generation deactivation each year over the 10-year period, 2020-2029. **Figure 2** is structured in the same manner but assumes that generation owners decide to deactivate during the first five years, between 2021 and 2025.

Specifically, in **Figure 1,** PJM subtracted from the 3,300 MW a levelized MW-per-year retirement amount for each of the 10 years between 2020 and 2029 for each retirement scenario. As **Figure 1** shows, based on those assumptions, PJM would likely be able to meet generation requirements with internal resources for the 6 MW and 16 GW scenarios. For the 32 GW scenario, however, PJM would not maintain sufficient resources to serve peak load be able to serve all load beginning in 2024.

Although it provides a base from which to demonstrate how timing plays a key role in resource adequacy, levelized generation retirement each year over the 10-year period is one possible path of retirements. Another possible path of retirements is for them all to take place early in the compliance period. In order to gain some perspective on how that might look, **Figure 2** assumes retirements are distributed evenly over the first five years of the period only – 2021 through 2025. Generation additions were maintained at 3,300 MW per year over the entire 10-year period, as in **Figure 1**. **Figure 2** shows that generation retirements could exceed needs by 2021 under the 32 GW deactivation scenario and by 2025 under the 16 GW deactivation scenario.

This capacity adequacy analysis bolsters PJM's assertion that timing is everything. If generators deactivate sooner than replacement generation is built, PJM could face capacity shortages and the inability to serve load reliably. In reality, the rate of generation additions will vary, depending on a range of factors. While transmission issues were "assumed away" for the purpose of examining resource adequacy alone, PJM reiterates that an RTO – or load deliverability area (LDA) for that matter — that cannot meet capacity needs internally must rely on transmission to import power in order to keep the lights on.

Figure 1. **Generation Reserves vs. At-Risk Retirement – 10-Year Even Distribution**

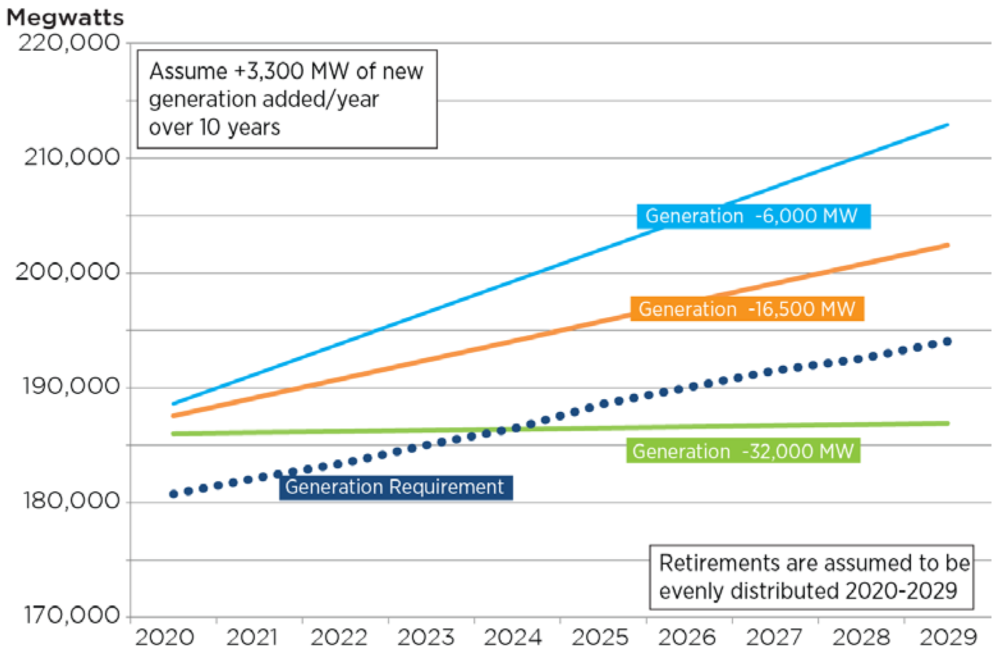
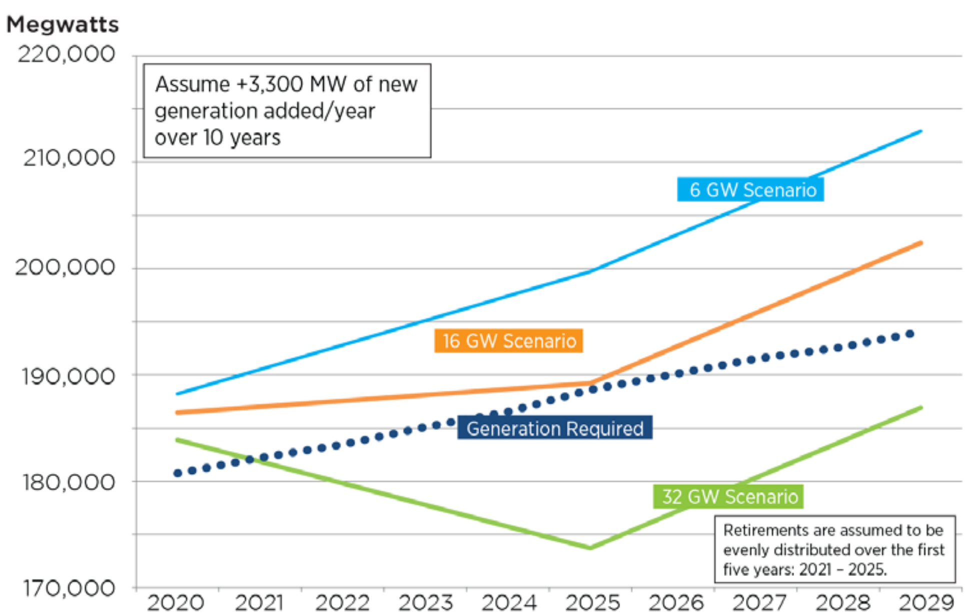


Figure 2. **Generation Reserves vs. At-Risk Retirement - First Five-Year Even Distribution**



Power Flow Analyses – Scope and Procedure

PJM has completed a set of "bookend" reliability scenario studies to assess the reliability implications from potential CPP retirements. Consistent with the OPSI's request, PJM conducted a series of reliability studies based on three levels of at-risk generation – 6 GW, 16 GW and 32 GW – shown in **Figure 3**. PJM also conducted several sensitivity analyses that considered lower reserves, heavy reliance on both energy efficiency and demand response and the location of replacement generation. The three at-risk generation levels used in these reliability study scenarios were based on the results of the economic evaluation summarized in **Appendix A.**

Studies included load and generator deliverability analysis and focused on monitored facilities at 230 kV and higher in an effort to identify the broader regional implications of the proposed rule. A cluster of conductor limit-based overloads into or within an area – as revealed by deliverability studies — would be indicative of a need for a new transmission feed into that area. Studies did not focus on reliability criteria violations limited by terminal equipment.

PJM's experience allowed it to make the reasonable assumption that any such limiting equipment could likely be upgraded within three years at nominal cost. By contrast, if larger scope upgrades — such as conductor replacements or new transmission lines — would be required, they would likely take more time to complete at much higher cost. In this reliability assessment, PJM focused on identifying broader regional issues. PJM did not attempt to identify reliability criteria violations below 230 kV, given the highly localized nature of the required upgrades in those instances.

Consistent with PJM's established Regional Transmission Expansion Plan process, PJM conducted these reliability studies to assess compliance with NERC and regional planning criteria. PJM's RTEP process rigorously applies NERC Planning Standards through the application of a wide range of reliability analyses, including load and generation deliverability tests. PJM's methodology included:

- Power flow case development for each scenario
- Identification of critical load deliverability areas (LDAs) to run based on the at-risk generation profile in each zone
- Capacity emergency transfer objective (CETO) value calculations for identified critical zones
- Load deliverability study tests to determine capacity emergency transfer limit (CETL) values for critical LDAs
- A systemwide generator deliverability test for single contingencies and a common mode outage study test for tower contingencies

RTEP analyses assess system compliance with the thermal, voltage (reactive), stability and short circuit standards specified by NERC and made mandatory by the FERC.

Case Development

Underlying RTEP studies are a set of power flow modeling assumptions and an extensive array of input data. Fundamentally, in order to complete all reliability criteria testing procedures, PJM must first incorporate expected future system conditions in its power flow simulation models – such as assumptions regarding load forecasts; development or deactivation of generation; transmission topology; demand resources, and power transfer levels between areas of the grid (known also as interchange). Notably, transmission topology includes approved baseline and network RTEP enhancements. Eastern Interconnection Reliability Assessment Group power flow cases provided the modeling parameters for areas external to PJM.

The process for developing the CPP scenario study power flow cases was no different. PJM conducted its analysis on its eight-year-out 2022 power flow case model, which was developed as part of the 2014 annual RTEP process. The 2022 case load level of 171,217 MW — shown in **Figure 3, Row 13** — was based on the 2014 PJM load forecast report that covered the planning horizon from 2014 through 2029.

In order to develop a power flow base case model, PJM assigns zonal load from its January forecast to individual zonal buses according to ratios of each bus load to total zonal load. Each transmission owner supplies the ratios. Specifically for load deliverability studies, zonal load is modified to account for load diversity, which lowers the overall peak load in each area, given that peak loads happen at different times in different geographical areas; in other words, they are non-coincident.

PJM interchange in the base case was set to be consistent with the long-term firm transmission service reservations through the PJM OASIS (Open Access Same-Time Information System). OASIS provides information about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis.

Generation Modeling

PJM's 2022 scenario study base case modeled all existing generation and respective expected output capability at system peak-load level. For existing generation resources, that capability is typically the capacity injection rights already assigned to each unit. For units that have or are seeking energy-only status, the unit's capability is set at the energy level sought. PJM also modeled all units that cleared the May 2013 Reliability Pricing Model base residual auction.[3]

Queued generation interconnection requests were modeled based on their status within PJM's interconnection study process. Consistent with established practice, generation with a signed Interconnection Service Agreement (ISA) was modeled together with associated network and attachment upgrades. Queued generation projects with an executed

[3] Any units with a signed Impact Study Agreement are allowed to bid into the RPM auction. When such units clear an RPM auction, they are then modeled in the RTEP power flow case in the same manner as a generator with an executed ISA.

Facility Study Agreement (FSA) were also modeled together with their associated network upgrades; however, consistent with PJM manuals, executed FSA-level queued projects were initially modeled offline in power flow cases. If existing and ISA-level generation was not enough to meet load, system real-megawatt losses and firm interchange, then FSA units were turned on and dispatched accordingly. Suspended queued projects were modeled offline in the base case. The energy portions of intermittent resources, such as solar and wind, were also modeled offline. ISA generation was allowed to contribute to, and back away from, transmission facilities experiencing reliability violations.

Scenario Model Development

PJM developed seven scenarios, labeled in **Figure 3** as columns S1 through S7. These were differentiated by the amount of generation at risk, reserve level modeled and replacement sourcing strategy as described here. Procedurally, PJM took its load forecast (Row 3), increased it by the reserve level (Row 2) and set that as its scenario generation requirement. That requirement was first satisfied by the following:

- Existing and ISA internal generation (Row 4) as adjusted for at-risk generation (Row 6)
- External generation (Row 10) as adjusted for external at-risk generation (Row 11)
- Load management and energy efficiency (Row 15)

Once these resources were accounted for, PJM took steps to satisfy any remaining scenario generation requirements with the following:

- Internal generation at the FSA stage in PJM's interconnection queue process (Row 5)
- Additional internal gas generation (Row 7) at the existing brownfield sites of each at-risk generator that was within one mile of existing gas pipeline infrastructure
- Additional renewable generation (Row 8), consistent with states' mandates
- Fixed injection rights (Row 12) associated with known external merchant transmission projects with western PJM termination points Collins 765 kV, Breed 345 kV and Erie West 345 kV. (These were not identified as uniquely providing power from wind resources external to PJM.)
- Additional internal energy efficiency (Row 17), consistent with states' mandates

The sourcing strategies for the scenarios in **Figure 3** are summarized below:

- **Scenario S1** – a 6 GW at-risk case with 18 percent reserve margin that required no additional replacement sources of generation beyond existing generation and queued generation that had executed an ISA or FSA (Rows 4 and 5)
- **Scenario S2** – a 16 GW at-risk case with 18 percent reserve margin; the additional 10 GW in this case required additional internal and external natural gas-fired resources (Rows 7 and 13) to meet scenario generation requirements

- **Scenario S3** – a 32 GW at-risk case with 18 percent reserve margin; this heavily stressed case required additional internal and external natural gas-fired resources (Rows 7 and 13), as well as external merchant transmission injection (Row 12) to meet scenario generation requirements
- **Scenario S4** – a 32 GW at-risk case with PJM's reserve requirement lowered to 15 percent; essentially, this required fewer additional internal natural gas-fired resources (Row 7) to meet scenario generation requirements
- **Scenario S5** – a 16 GW at-risk case in which replacement generation needs were satisfied with internal renewable resources (Row 8) and energy efficiency (Row 16) to meet state renewable portfolio standards mandates, instead of additional internal natural gas-fired units (Row 7), external natural gas-fired units (Row 13) and external merchant transmission injection (Row 12); PJM reserves amounted to 22 percent
- **Scenario S6** – a 32 GW at-risk case with PJM's reserve requirement set at 18 percent; this heavily stressed case mirrored Scenario S3; here, though, 70 percent of additional internal natural gas-fired generation (Row 7) was sourced instead with internal renewables (Row 8) and energy efficiency (Row 16)
- **Scenario S7** – a 32 GW at-risk case with PJM's reserve requirement set at 18 percent; this heavily stressed case mirrored S6 except that the additional internal natural gas-fired generation (Row 7) was modeled from shale gas regions in western Pennsylvania and West Virginia.

In Scenarios 5 and 6, PJM converted annual state-mandated renewable and energy efficiency energy values to a snapshot MW amount. State numbers were translated into zonal values. Modeling these resources yielded a 22 percent reserve margin, more than needed even in conventional annual RTEP process analyses. PJM also notes that locations of wind-powered generation for Scenario 5 and 6 – significant amounts of which are in western PJM – are not likely to be built at the deactivating generation brownfield sites as in Scenarios 1, 2 and 3.

Figure 3. **Scenario Generation and Load Modelling**

Ref	Scenario	S1	S2	S3	S4	S5	S6	S7
1	**At-Risk Generation**	**6 GW**	**16 GW**	**32 GW**	**32 GW**	**16 GW**	**32 GW**	**32 GW**
2	**Reserves**	**18%**	**18%**	**18%**	**15%**	**22%**	**18%**	**18%**
3	**Load (MW)**	**171,217**	**171,217**	**171,217**	**171,217**	**171,217**	**171,217**	**171,217**
	Internal Generation							
4	Existing + ISA Generation [+]	184,112	184,112	184,112	184,112	184,112	184,112	184,112
5	FSA Generation [+]	5,680	12,075	12,075	12,075	12,075	12,075	12,075
6	At Risk Generation [-]	5,937	14,979	29,871	29,871	14,979	29,871	29,871
7	Additional Gas Generation [+]	0	3,241	14,632	9,555	0	4,426	4,426*
8	Additional Renewable Generation [+]	0	0	0	0	2,872	2,872	2,872
9	**TOTAL Internal Generation (MW)**	**183,855**	**184,449**	**180,948**	**175,871**	**184,080**	**173,614**	**173,614**

Ref	Scenario	S1	S2	S3	S4	S5	S6	S7
	External Generation							
10	2019 RTEP Case [+]	5,000	5,000	5,000	5,000	5,000	5,000	5,000
11	At Risk Generation [-]	198	1,407	2,219	2,219	1,407	2,219	2,219
12	Additional MTX FTIRs ** [+]	0	0	3,700	3,700	0	3,700	3,700
13	Additional Gas Generation [+]	0	614	1,228	1,228	0	1,228	1,228
14	**TOTAL External Generation (MW)**	**4,802**	**4,207**	**7,709**	**7,709**	**3,593**	**7,709**	**7,709**
	Load Management + Energy Efficiency							
15	2014 PJM Load Forecast [+]	13,320	13,320	13,320	13,320	13,320	13,320	13,320
16	Additional EE [+]	0	0	0	0	7,334	7,334	7,334
17	**TOTAL LM+EE (MW)**	**13,320**	**13,320**	**13,320**	**13,320**	**20,654**	**20,654**	**20,654**

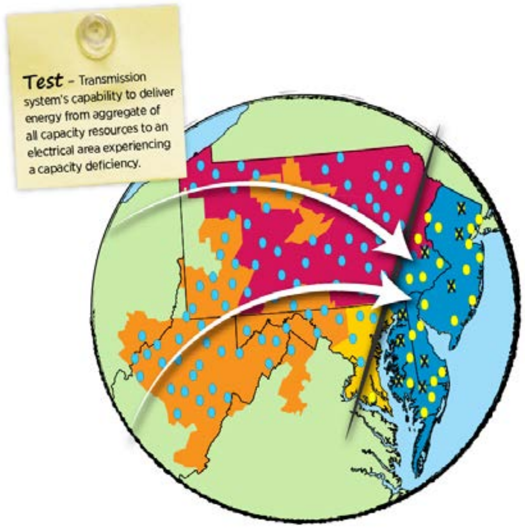
NOTES
* For Scenario 7, the additional gas generation came from shale gas regions in Western PA and WV
** In Row 12, the merchant transmission injections were not identified as uniquely providing power from wind resources external to PJM.

Load Deliverability Test

When an area cannot meet its load-serving requirement from internally generated power – whether an individual LDA or the PJM area as a whole – it must import it. Transmission lines become more heavily loaded to the degree that generation is removed from an area and not replaced with the same quantity MW at the same location. If either or both location and quantity differ from what was originally there, transmission flows are altered. That is essentially the nature of deliverability tests from a transmission-planning perspective.

PJM's load deliverability test requires that the transmission system must be robust enough to deliver energy from an aggregate of all capacity resources to an LDA experiencing a capacity deficiency, shown conceptually in **Figure 4.** The test ensures that load inside an LDA can be served by generating resources outside that LDA. If sufficient generating capacity cannot be delivered to load as a result of one or more limiting transmission constraints, the LDA fails the load deliverability test. The methodology requires that each LDA under test be modeled at a higher than normal load level – 10 percent probability of occurring – with higher levels of unavailable generation than normal. Load deliverability studies test the transmission system's capability to import sufficient energy to meet a defined capacity emergency transfer objective.

Figure 4. **Load Deliverability Test Concept**

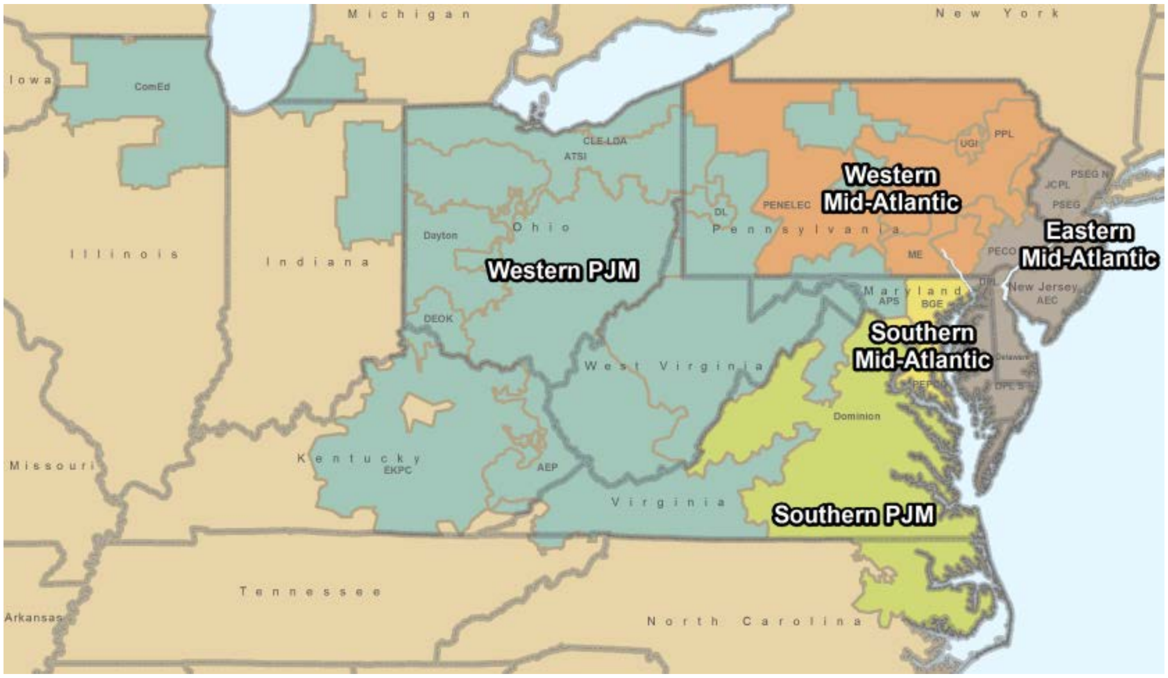


The CETO calculated for the load deliverability test is the import capability required for the area to meet a loss-of-load expectation risk level of one event in 25 years. The risk refers to the probability that an LDA would need to shed load due solely to its inability to import needed capacity assistance during a capacity emergency (i.e., the transmission system is not robust enough to import sufficient power during a capacity emergency). PJM calculates a CETO value for each of the LDAs using a realistic probable model of the load and capacity located within each LDA. The model recognizes, among other factors, historical load variability, load forecast error, generating unit maintenance requirements and generating unit forced outage rates. A number of factors drive CETO value increases, including the following:

- LDA peak load increase
- LDA capacity resource decreases including generation, demand resource programs and energy efficiency
- LDA capacity resources

CETO values calculated for the CPP analyses took into account the deactivation of at-risk generation within each LDA. Under PJM's RTEP process, load deliverability power flow analysis results identify the CETL for each LDA**.** This value represents the maximum megawatts that an LDA can import under specified peak-load test conditions. Transmission system topology changes, including the addition (or removal) of transmission facilities and changes in the load distribution profile within a zone, impact CETL levels, as do the addition and retirement of generation facilities. Each LDA is tested for its expected import capability up to established transmission facility limits, indicating how much an area can actually be expected to import. If the CETL value is less than CETO, the test fails, indicating the need for additional transmission capability. Transmission limits are defined in terms of facility thermal ratings and voltage limits.

Figure 5. **Locational Deliverability Areas**



PJM conducted scenario study load deliverability studies consistent with established RTEP processes for LDAs selected based on the at-risk generation profile in each zone. The 17 LDAs shown in **Figure 6** were selected from the existing 27 based on CETO/CETL ratios indicating LDAs that might be limited due to the magnitude of the at-risk generation within each of them. PJM adopted this approach to put boundaries around the scope of the analysis. Each scenario for each LDA required the development of a unique power flow case for thermal and voltage analysis to which contingencies were applied.

Figure 6. **Locational Deliverability Areas Studied**

LDA*	S1 6 GW	S2 16 GW	S3 32 GW	S4 32 GW	S5 16 GW	S6 32 GW	S7 32 GW
BGE	x	x	x	x	x	x	x
DPL	x	x	x	x	x	x	x
DPL South	x	x	x	x	x	x	x
Dayton	x	x	x	x	x	x	x
Dominion	x	x	x	x	x	x	x
AEP	x	x	x	x	x	x	x
EKPC	x	x	x	x	x	x	x
ATSI		x	x	x	x	x	x
ComEd		x	x	x	x	x	x
DEO&K		x	x	x	x	x	x
Southern Mid-Atlantic	x	x	x	x	x	x	x
Western PJM	x	x	x	x	x	x	x

	S1	S2	S3	S4	S5	S6	S7
LDA*	**6 GW**	**16 GW**	**32 GW**	**32 GW**	**16 GW**	**32 GW**	**32 GW**
AE			x	x		x	x
PPL			x	x		x	x
PENELEC			x	x		x	x
Western Mid-Atlantic			x	x		x	x
Mid-Atlantic			x	x		x	x

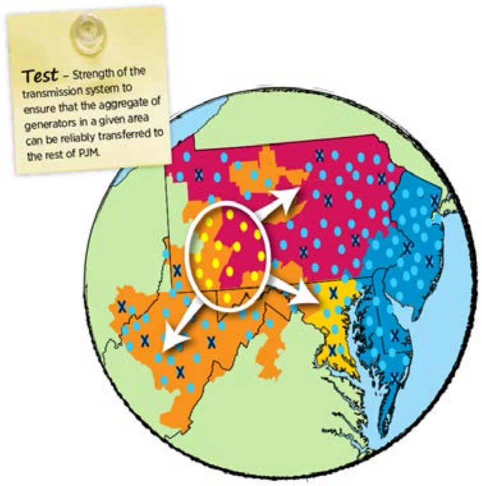
*NOTE: Full LDA definitions are provided in **Appendix B**.

Generation Deliverability and Common Mode Analysis

Generator deliverability testing ensures that the transmission system will not limit delivery of capacity resources, so that generation is not "bottled" when needed. The test considers both the ramping impact of generators that are electrically close to a particular flowgate and the ramping impact of queued generation that is electrically further away. Generator deliverability testing ensures sufficient transmission capability to export generation capacity in excess of forecasted peak load from an area to the aggregate of PJM load. Specifically, the scope of generator deliverability tests the strength of the transmission system to ensure that the excess capacity of an aggregate of generators in a given area can be reliably transferred to the rest of PJM, as shown in **Figure 7**. Generator deliverability testing is used to assess Category A and B contingencies as part of baseline analysis, and as part of queued interconnection request studies.

PJM analysis also included Category C common mode contingencies. Common mode contingency studies determine the impact of losing multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double circuit tower line outages and stuck breaker events.

Figure 7. **Generation Deliverability Test**



Transmission Limits

Transmission limits are defined in terms of facility thermal ratings and voltage limits. From a planning perspective, a thermal overload occurs on a bulk electric system facility if flow on that facility exceeds 100 percent of one of the following:

- The facility's normal rating with all facilities in service (NERC Category A)
- The facility's emergency rating following the loss of a single facility (NERC Category B)

Likewise, voltages are also monitored for compliance with existing voltage limits specified in terms of permissible bus voltage level and contingency voltage drop, as specified by PJM Operations. Consistent with deliverability studies for thermal criteria violations, PJM's load deliverability testing methodology also evaluates compliance with reliability voltage criteria.

Power Flow Analyses – Results

Thermal Analysis

PJM's load deliverability thermal analysis identified 25 potential thermal overloads – flows above conductor limits – as shown in **Figure 8** and **Figure 9**. The studies show a range of potential issues under varying assumptions across the RTO, the timing of which will dictate when they would arise and the magnitude of their impact. The results provide PJM with several key observations by which to make informed RTEP decisions.

- The results confirm PJM's expectation that the number, location and severity of the issues PJM may see will depend on the amount of generation that ultimately will retire and the amount and location of the generation that would replace it. For example, looking at the different 32 GW scenarios reveals different sets of potential overloads. The only differences between the scenarios were assumptions about the type and location of generation and/or energy efficiency that was added back.

- These scenario studies suggest that overloads clustered along specific corridors – such as those observed in the BGE LDA shown on **Figure 9 –** may require additional review. That review would necessarily need to assess the feasibility of certain types of upgrades, which in turn would impact both the cost of solving identified reliability criteria violations and the ability to complete construction of facilities in time to avoid those violations.
- In some instances, multiple scenarios suggest that individual facilities bear a higher likelihood of needing solutions to reliability criteria violations than others.

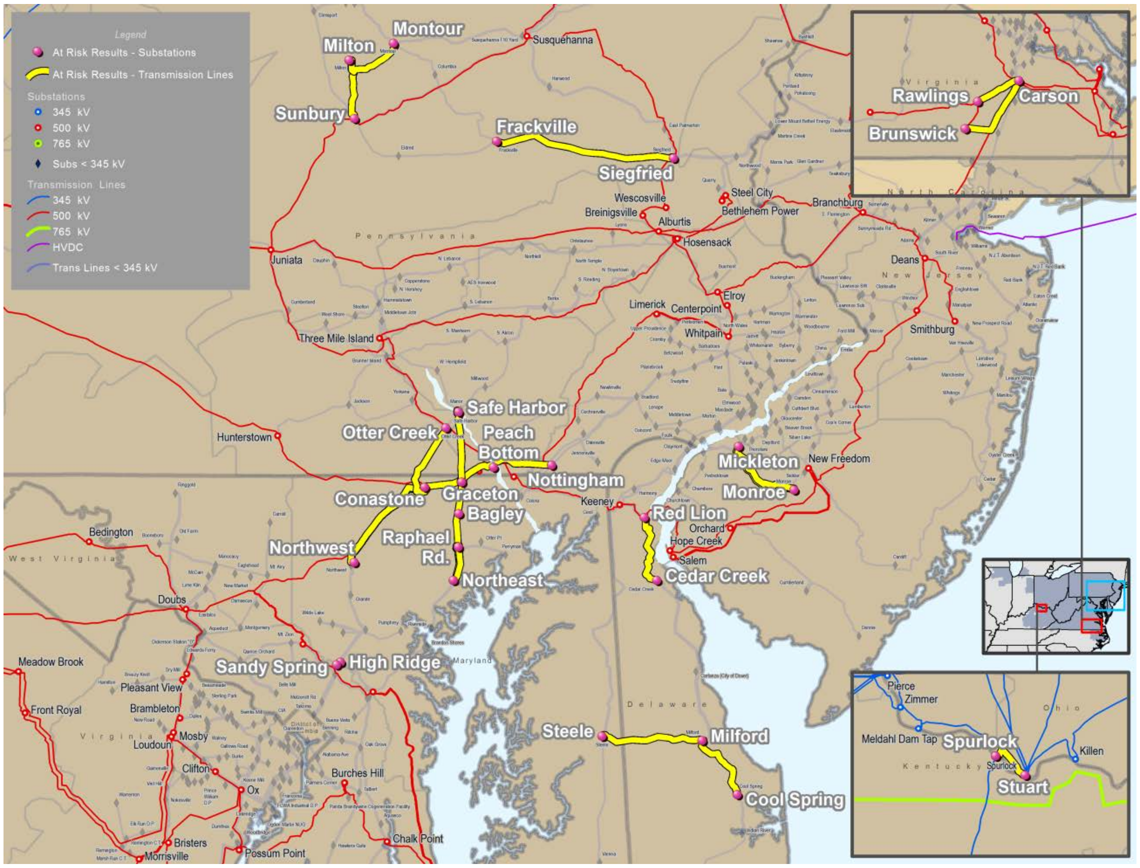
Potential solutions and their costs are yet to be studied.

Figure 8. **Potential Thermal Violations**

Transmission Facility	**Voltage Level kV**	**LDA(s)**	**S1 (6 GW)**	**S2 (16 GW)**	**S3 (32 GW)**	**S4 (32 GW)**	**S5 (16 GW)**	**S6 (32 GW)**	**S7 (32 GW)**
Mickleton – Monroe #1	230	AE	x			x	x	x	x
Mickleton – Monroe #2	230	AE	x			x	x	x	x
Bagley - Raphael Road #1	230	BGE							x
Bagley - Raphael Road #2	230	BGE							x
Conastone - Northwest '311'	230	BGE					x		x
Conastone - Northwest '326'	230	BGE		x	x	x	x	x	x
Graceton - Bagley	230	BGE							x
Raphael Road - Northeast '317'	230	BGE							x
Raphael Road - Northeast '339'	230	BGE							x
Sandy Springs '14' - High Ridge '16'	230	BGE				x			
Sandy Springs '34' - High Ridge '16'	230	BGE				x			
Stuart - Spurlock	345	Dayton / EKPC				x		x	x
Brunswick - Carson	500	Dominion	x	x	x	x		x	
Rawlings - Carson	500	Dominion	x	x	x	x		x	
Milford - Cool Springs	230	DPL				x			
Red Lion - Cedar Creek	230	DPL	x	x		x	x	x	x
Steele - Milford	230	DPL	x	x		x	x		
Nottingham - Nottingham Reactor	230	PECO						x	x
Nottingham Reactor - Peach Bottom	230	PECO						x	
Peach Bottom - Conastone	500	PECO, BGE						x	x

Transmission Facility	Voltage Level kV	LDA(s)	S1 (6 GW)	S2 (16 GW)	S3 (32 GW)	S4 (32 GW)	S5 (16 GW)	S6 (32 GW)	S7 (32 GW)
Frackville - Siegfried	230	PPL	x	x	x		x		
Milton - Sunbury	230	PPL					x	x	x
Montour - Milton	230	PPL	x	x	x	x	x	x	x
Otter Creek - Conastone	230	PPL, BGE							x
Safe Harbor - Graceton	230	PPL, BGE					x	x	x

Figure 9. **Potential Thermal Violations**



Voltage Analysis

Reliability studies also showed the potential for reliability criteria voltage violations in the BGE and DPL LDAs. The types of issues identified are unit-specific and depend on both the reactive capability of the unit retiring and the existing reactive support in the area. Experience indicates the voltage issues identified can be fixed with solutions that do not require long lead times. Given the unit-specific nature of the issues, PJM can address them as each unit retirement notification is formally received.

Next Steps

The reliability study results presented in this white paper provide a first glimpse into the types of potential CPP impacts PJM could face. Once the CPP rule is finalized, PJM will be in a better position to pursue additional scenario studies to understand the rule's impact more fully.

Depending on the language of the final rule, PJM may see merit in revisiting assumptions that drive which units may be at risk of deactivation -- especially as states continue to develop their respective compliance plans. Other assumptions could be updated at that time, including transmission topology, interconnection queue changes and load forecast information.

Once potential overloads are identified, as in this white paper, PJM can also pursue development of conceptual overlays to offer states and other PJM stakeholders an idea of the scope of addressing CPP impacts. For example, solutions to solve the identified thermal overloads could warrant reconductoring existing lines or constructing new lines altogether. Solution decisions would depend on such factors as the severity of the overload and the location where new transmission capability would be needed.

Appendix A

At-Risk Generation Levels – Economic Study Background

On Sept. 2, 2014, the Organization of PJM States, Inc. (OPSI) requested analysis from PJM to evaluate the economic and reliability impacts of the U.S. Environmental Protection Agency's Clean Power Plan (proposed on June 2, 2014). PJM completed its economic evaluation and presented its results in the March 2, 2015 report.

PJM used units that were identified as at-risk generating units in that report to conduct the reliability studies discussed in this report. This **Appendix** summarizes how the 6 GW, 16 GW and 32 GW at-risk generation levels were determined for the reliability scenario studies described earlier in this report.

Economic analysis comprised 17 different scenarios designed to encompass a range of possible future states as the industry heads into CPP compliance. Scenarios included mass-based regional compliance scenarios, state-by-state mass-based compliance scenarios and an emission rate-based regional compliance scenario. Outputs from the economic study included information about generator net-energy market revenues and an assessment of generation at risk for retirement. "At risk" means those generating resources anticipate facing varying financial challenges from the proposed rule; it does not mean that resources will necessarily retire. Varying degrees of at-risk generation must look at how much additional revenue will be needed from the capacity market for the resource to go forward, as measured against a Net Cost of New Entry (Net CONE) index.

OPSI requested that PJM analyze potential economic impacts of the proposed CPP under a variety of scenarios. Production cost simulation outputs included: total emissions, emissions rates and resulting CO_2 prices, locational marginal price effects, changes in energy market payments by load, percentage of generation by fuel type, generator net energy market revenue, and compliance costs. Generator net energy market revenues were used to conduct an assessment of fossil-steam generation at risk for retirement -- primarily coal, but also oil- and gas-fired steam units.

Finally, OPSI requested analysis of regional compliance options versus state-by-state compliance options under a limited set of scenarios and years. PJM's production cost simulation modeling platform performed a security-constrained economic dispatch based on a weekly security-constrained unit commitment and hourly dispatch for user-defined time periods. The granular dispatch enabled more detailed and accurate generating unit representation, as well as representation of the transmission system on a nodal basis.

In addition, PJM supplemented the scenarios requested by OPSI with eight additional scenarios with varying assumptions regarding natural gas prices, available energy efficiency, renewable energy resources, and available new entry of renewable energy and natural gas combined-cycle resources. PJM also studied three additional individual state compliance scenarios and an emissions rate-based compliance scenario. PJM's chose these additional scenarios to supplement the OPSI request and provide model results over a wide range of possible outcomes.

In total, PJM studied 17 different scenarios, each run with and without the limits set forth in the CPP. The years 2020, 2025 and 2029 were chosen to examine the effects of the plan at the start of the interim compliance period, halfway through the interim period and the final targets.

PJM largely employed the same production cost modeling approach it uses in the market efficiency analyses that are embedded in the RTEP process. Unlike PJM's market efficiency or interregional planning models used in the RTEP process (where economic interchange is represented between PJM and its neighbors), this analysis focused only on PJM's dispatch. First, the proposed plan will likely have very different economic and reliability impacts on PJM's neighbors because of differing resource mixes, regulatory frameworks and stakeholder processes. Second, earlier environmental policies such as the Mercury and Air Toxics Standards have reinforced market trends away from coal to natural gas. Most regions within the Eastern Interconnection will continue to undergo significant transformation, with or without the CPP. As a consequence, modeling economic energy transfers between PJM and other regions would only add uncertainty and complexity in interpreting the results. PJM elected to dispatch only its own resources to serve load within the PJM footprint in the modeling.

Defining "At-Risk"

Assessing the quantity of fossil steam capacity at risk for retirement requires knowing the revenue streams that fossil steam resources require in order to cover going-forward or avoidable costs, such as fixed operations and maintenance costs, fixed labor costs and other associated overhead. In this analysis, the benchmark comparison is some percentage of the Net CONE of a natural gas combustion turbine, defined as the reference resource in the PJM RPM capacity market. PJM chose a benchmark of 0.5 Net CONE as defining being at risk for retirement consistent with its study on the effects of the MATS and Cross-State Air Pollution Rule in 2011.

The net CONE values used in these OPSI studies adjusted Gross CONE value for inflation to the simulation year — 2020, 2025 and 2029. Net Energy Market Revenues were derived for the combustion turbine directly from the production cost simulations. Given the different assumptions in each simulation scenario, and consistent with what PJM expected, Net CONE values can change significantly and affect the quantity of fossil steam capacity potentially at risk for retirement. PJM notes, however, that simply because a unit is considered at risk for retirement in this analysis does not mean that the unit would actually retire. That unit could still be committed in the capacity market and receive capacity revenue that, combined with its energy market revenue, would continue to ensure its financial viability. PJM has not simulated capacity market outcomes associated with the energy market results.

What the results revealed…

Given the definition just discussed, PJM defined scenario groupings shown in **Figure 10** according to criteria defined in terms of Net CONE.

Figure 10. **Definitions of At-Risk Scenario Groupings**

Scenario Group	Criteria
All Scenarios in all years	Generator fails to meet the 0.5 Net CONE Criteria in all scenarios for all years
50% of Scenarios	Generator fails to meet the 0.5 Net CONE Criteria in greater than 50% of the scenarios
Worst Case Scenarios	Generator fails to meet the 0.5 Net CONE criteria for each of the worst case scenarios (OPSI 2b.4, PJM 2, PJM 8)
High Renewable/EE	Generator fails to meet the 0.5 Net CONE criteria for each of the high renewable scenarios (OPSI 2a, OPSI 2b.1, OPSI 2b.2, PJM 1)
Low Renewable/EE	Generator fails to meet the 0.5 Net CONE criteria for each of the low renewable scenarios (PJM 4, PJM 5, PJM 6 & PJM 7)

Figure 11 shows the amount of capacity at risk for retirement across all of the scenarios in 2025, based on combustion turbine Net CONE, which is the reference resource in the RPM capacity market for setting the demand for capacity. In addition, PJM also assessed the amount of at-risk capacity as benchmarked against least-cost Net CONE in 2025, as shown in **Figure 12.**

Figure 11. **At-Risk Generation – Combustion Turbine Net Cone Benchmark**

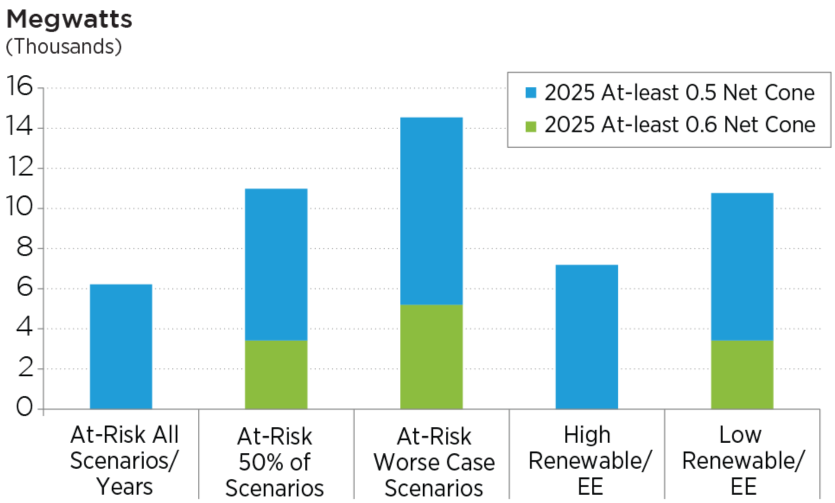
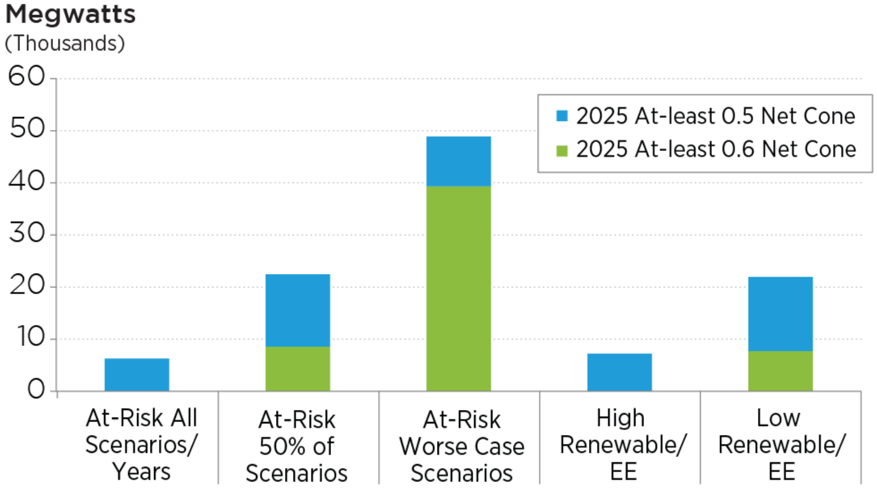


Figure 12. **At-Risk Generation – Least-Cost Net CONE as the Benchmark**



Reliability studies assessed the system impact of at-risk generation based on degree of risk identified from 2025 simulations and taking the average between combustion turbine Net CONE and least-cost Net CONE benchmarks per **Figure 11** and **Figure 12**.

- "At risk" in all simulations equated to 6,200 MW
- "At risk" in at least 50 percent of simulations equated to 16,500 MW
- "At risk" in "worst case" simulations equated to 32,000 MW

PJM notes that units that have already announced deactivation were not included in the economic analysis, which focused instead on incremental retirement risk.

Appendix B

Load Deliverability Area (LDA) Definitions

BGE	Baltimore Gas and Electric
DPL	Delmarva Power and Light
DPL South	Southern Portion of DPL
Dayton	Dayton Power and Light
Dominion	Dominion Virginia Power
AEP	American Electric Power
EKPC	East Kentucky Power Cooperative
ATSI	American Transmission Systems, Incorporated (First Energy)
ComEd	Commonwealth Edison
DEO&K	Duke Energy Ohio and Kentucky
Southern Mid-Atlantic	Global area - BGE and PEPCO
Western PJM	Global area - APS, AEP, Dayton, DLCO, ComEd, ATSI, DEO&K, EKPC
AE	Atlantic City Electric
PPL	PPL Electric utilities Corporation, UGI
PENELEC	Pennsylvania Electric
Western Mid-Atlantic	Global area - PJM 500 kV, PENELEC, METED, PPL
Mid-Atlantic	Global area - PJM 500, Eastern Mid-Atlantic, Southern Mid-Atlantic, Western Mid-Atlantic
Eastern Mid-Atlantic	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO Energy Company
PSEG	Public Service Electric and Gas
PEPCO	Potomac Electric Power Company
APS	Allegheny Power
DLCO	Duquesne Light Company
CLE	Cleveland area