UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) ER19-469-000

PROTEST OF THE AMERICAN WIND ENERGY ASSOCIATION AND THE SOLAR COUNCIL

Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"),[1] the American Wind Energy Association ("AWEA")[2] and the Solar Council[3] (collectively, the "Clean Energy Entities") respectfully submit this protest ("Protest") in response to the December 3, 2018, compliance filing of PJM Interconnection, L.L.C. ("PJM")[4] to Commission Order No. 841.[5] Specifically, the Clean Energy Entities protest PJM's practice of determining electric storage resources' ("ESR"[6])

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[1] 18 C.F.R. § 385.211.

[2] AWEA is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States. AWEA's members include active participants in the markets administered by PJM.

[3] The Solar Council is a group of companies participating in AWEA's RTO Advisory Council that own, operate, develop, and finance solar projects and act, in coordination with AWEA, to advance joint goals before the Federal Energy Regulatory Commission and the nation's regional transmission markets and independent system operators.

[4] Order No. 841 Compliance Filing- ESR Markets and Operations Proposal, Docket No. ER19-469-000 (Dec. 3, 2018) ("PJM Compliance Filing").

[5] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018) ("Order No. 841").

[6] In Order No. 841, the Commission defined ESRs as "a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid," and clarified that "this definition is intended to cover electric storage resources capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid, regardless of their storage medium (e.g., batteries, flywheels, compressed air, and pumped-hydro)." *See id.* at P 29. Unless otherwise indicated, the Clean Energy Entities references to "ESRs" refer to the definition of ESRs adopted by the Commission in Order No. 841. Further, the Clean Energy Entities will sometimes refer to "non-hydro ESRs" herein, meaning that the Clean Energy Entities intend to refer to ESRs that are not pumped-hydro in such instances.

capacity value (in installed capacity MWs) "based on their discharge/output capability over ten hours of sustained continuous operation"[7] (hereinafter, the "10-hour duration requirement").

I. INTRODUCTION

The Clean Energy Entities support many aspects of the PJM Compliance Filing and believe that in general it will lead to more transparent and fair rules for ESRs seeking to participate in PJM's markets. However, one glaring exception to the overall positive PJM Compliance Filing is PJM's practice of imposing the 10-hour duration requirement when calculating ESRs' capacity value, which leads to an unjustifiably low capacity value for ESRs, and particularly for non-hydro ESRs. While PJM states that this is its current practice, and "long has used to determine the capacity value of pumped-storage hydroelectric resources installed in the PJM Region,"[8] PJM's practice of imposing a 10-hour duration requirement on non-hydro ESRs when determining non-hydro ESRs' capacity value does not comply with Order No. 841 as it erects an arbitrary, unsupported and unnecessary barrier for non-hydro ESRs seeking to participate in PJM's capacity market. As explained further in the Prepared Testimony of Dr. Emma L. Nicholson ("Nicholson Affidavit),[9] and in Section II.B below, PJM's proposed 10-hour duration requirement is not supported by the information contained in the PJM Compliance Filing from a technical perspective when applied to non-hydro ESRs. Further, as described in Section II.C below, PJM's current governing documents[10] and manuals do not support imposing the 10-hour duration requirement on ESRs under any reasonable interpretation.

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[7] *See* PJM Compliance Filing at 20.

[8] *See id.*

[9] The Nicholson Affidavit is attached hereto as Attachment A.

[10] PJM's governing documents are the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA").

Accordingly, for these reasons and as further specified herein, the Clean Energy Entities request that the Commission grant the relief requested in Section III of this Protest. To summarize the requested relief, the Clean Energy Entities request that the Commission: 1) order PJM to cease its practice of imposing the 10-hour duration requirement when calculating non-hydro ESRs' capacity values and find that doing so is a violation of Order No. 841; and 2) order PJM to utilize a 4-hour duration requirement for non-hydro ESRs because doing so is in accordance with the most logical interpretation of PJM's currently effective governing documents and manuals; or 3) in the alternative, order PJM to utilize a 4-hour duration requirement for non-hydro ESRs on an interim basis so that non-hydro ESRs may offer capacity into the upcoming August 2019 Base Residual Auction ("BRA")[11] in a just and reasonable manner.

The Clean Energy Entities are particularly concerned about the 10-hour duration requirement because they represent companies that are among the largest developers, owners, operators, and investors in utility-scale renewable energy projects in the country, including in PJM. Importantly, increasing numbers of the Clean Energy Entities' member companies are developing facilities being referred to as "hybrid resources" – *i.e.* renewable energy projects that also incorporate non-hydro ESRs. Many issues related to hybrid resources are outside the scope of Order No. 841 and will be developed in the future in PJM and elsewhere, and accordingly are not addressed in the PJM Compliance Filing or this Protest. However, imposing an unsupported and unjust 10-hour duration requirement on non-hydro ESRs in PJM will make it more likely that prospective rules for hybrid resources will be developed in PJM in a manner that will fail to

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[11] *See e.g. PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,153, at P 1 (2018) (granting PJM's waiver request to delay the 2019 BRA from May 2019 until August 2019) ("2019 BRA Order").

properly account for the full capacity value of hybrid resources (or any type of resource seeking to pair with non-hydro ESRs), and lead to unjust and unreasonable market outcomes.

II. PROTEST

A. Overview of Why The 10-Hour Duration Requirement is Not In Compliance With Order No. 841

In Order No. 841, the Commission adopted "reforms to remove barriers to the participation of electric storage resources in the Regional Transmission Organization and Independent System Operator markets,"[12] and ordered each Commission-jurisdictional regional transmission organization and independent system operator (collectively, "RTO") "to revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets."[13] Importantly, the Commission stated that "the tariff provisions for the participation model for electric storage resources must (1) ensure that a resource using the participation model for electric storage resources is eligible to provide all capacity, energy, and ancillary services *that it is technically capable of providing* in the RTO/ISO markets,"[14] and further clarified "that 'technically capable' of providing a service means that a resource can meet

[12] Order No. 841 at P 1.

[13] *See id.* at P 3.

[14] *See id.* at P 4 (emphasis added). The Commission also stated that each participation model must "(2) ensure that a resource using the participation model for electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price; (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and (4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW. Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price (LMP)." *See id.* The Clean Energy Entities clarify that these other ESR participation model requirements are not relevant to the issues raised in this Protest, nor do the Clean Energy Entities take any position on whether any aspect of the PJM Compliance Filing complies or does not comply with these other ESR participation model requirements.

all of the technical, operational, and/or performance requirements that are *necessary to reliably provide that service*."[15]

Additionally, the Commission noted that while it was clarifying the definition of "technically capable" in Order No. 841, it also held that it was "not considering in this proceeding the requirements that determine whether resources are technically capable of providing individual wholesale services,"[16] and "[t]o the extent that an RTO/ISO seeks to revise its tariff provisions setting forth the technical requirements for providing any specific wholesale service, the RTO/ISO may propose such revisions to its tariff through a separate FPA section 205 filing."[17]

When examining these key holdings of Order No. 841, and for the reasons explained in further detail herein, it is clear that PJM's imposition of the 10-hour duration requirement when calculating non-hydro ESRs' capacity value is not in compliance with Order No. 841 for two overarching reasons. First, PJM has not shown that the 10-hour duration requirement is necessary in order for non-hydro ESRs to "reliably provide" capacity, and accordingly have established an unjust and unreasonable barrier to non-hydro ESRs' participation in the capacity market by not allowing non-hydro ESRs to fully provide a service (*i.e.* capacity) which they are "technically capable of providing."[18] This is a direct violation of Order No. 841 and the accompanying regulatory text that was specifically added to the Commission's applicable

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[15] *See id.* at P 77 (emphasis added).

[16] *See id.*

[17] *See id.* at P 77, n. 106.

[18] *See id.* at P4.

regulations.[19] Second, PJM cannot utilize the 10-hour duration requirement when calculating non-hydro ESRs' capacity value because it is not a practice that is permitted under any reasonable interpretation of PJM's current governing documents and manuals, and thus is not part of PJM's currently effective filed rate. Accordingly, PJM cannot impose what is effectively a new requirement related to measuring non-hydro ESRs' capacity value through its compliance filing. Instead, per Order No. 841, PJM would have to establish the 10-hour duration requirement prospectively and show that it is needed to "determine whether resources are technically capable of providing individual wholesale services,"[20] (*i.e.* capacity), and thus would need to establish the 10-hour duration requirement "through a separate FPA section 205 filing."[21]

For these reasons, and for the reasons further specified herein and in the Nicholson Affidavit, the Commission must reject PJM's imposition of the 10-hour duration requirement when calculating non-hydro ESRs' capacity value.

B. PJM Has Failed to Demonstrate Why The 10-Hour Duration Requirement is Necessary For ESRs to "Reliably Provide" Capacity in PJM.

As noted, the overriding purpose of Order No. 841 was to "remove barriers to the participation of electric storage resources**"** in RTOs.[22] The 10-hour duration requirement certainly acts as a barrier to ESRs participating in PJM's capacity market, especially when taking into account: 1) the fact that *no other Commission-jurisdictional RTO* imposes a 10-hour duration requirement when qualifying non-hydro ESRs' capacity value; and 2) the Commission

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[19] *See id.* at P 76 (noting that "[t]o provide clarity, we add the phrase 'technically capable of providing' to the regulatory text we proposed in the NOPR.").

[20] *See id.* at P 77.

[21] *See id.* at P 77, n. 106.

[22] *See* Order No. 841 at P 1.

indicated in Order No. 841 that a 4-hour duration requirement was an acceptable length when determining whether ESRs could reliably provide capacity.

More specifically, the Midcontinent Independent System Operator, Inc. ("MISO"), the New York Independent System Operator, Inc. ("NYISO"), and the California Independent System Operator Corporation ("CAISO") impose a 4-hour duration requirements with respect to qualifying ESRs' capacity values, or are proposing to impose a 4-hour duration as part of their compliance filings in response to Order No. 841.[23] Furthermore, ISO-New England, Inc. ("ISO-NE"), which has a capacity market design that is very similar to PJM's capacity market design, imposes a mere *2-hour* duration requirement for ESRs seeking to participate in ISO-NE's capacity market.[24] Last, based on the Clean Energy Entities' review, the Southwest Power Pool, Inc. ("SPP") does not appear to have specified hourly duration requirements for qualifying ESRs' capacity values.

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[23] *See* Midcontinent Independent System Operator, Inc.'s Filing to Revise Tariff as Necessary in Compliance with Order No. 841, Docket No. ER19-465-000, at Tab A (Proposed Tariff Revisions), Section 69A.3.1.d (Dec. 3, 2018) ("The Market Participant shall identify eligible Generation Resources, Electric Storage Resources or External Resources to the Transmission Provider that are Use Limited Resources. . . . A Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in order to qualify as a Capacity Resource, in accordance with the BPM for Resource Adequacy."); New York Independent System Operator, Inc.; Compliance Filing and Request for Extension of Time of Effective Date; Docket Nos. RM16-23-000, AD16-20-000, ER19-467-000, at 44 (Dec. 3, 2018) ("The NYISO proposes to insert a new Section 5.12.1.13 of the Services Tariff to provide that an Energy Storage Resource seeking to qualify as an Installed Capacity Supplier must 'be capable of running for a minimum of four (4) consecutive hours each day . . .'"); *See* CAISO Tariff, Section 40.8.1.16 ("The CAISO will determine the Net Qualifying Capacity of each Non-Generator Resource based on the CAISO testing of the resource's sustained output over a four-hour period."). Section 40.8 addresses CAISO's "Default Qualifying Capacity Criteria," and "Non-Generator Resources" are functionally ESRs under CAISO's tariff. *See* CAISO Tariff, Appendix A-Master Definition Supplement (defining Non-Generator Resources as "[r]esources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy.").

[24] *See e.g.* Revisions to ISO New England Inc. Transmission Markets and Services Tariff in Compliance with FERC Order 841, Docket No. ER19-470-000, at 15 (Dec. 3, 2018) ("The ISO-NE market rules require resources to meet the following minimum run times: as previously explained . . . in the Forward Capacity Market, two hours for the provision of capacity by an electric storage resource.").

Furthermore, in requiring each RTO to revise its tariff to allow ESRs to de-rate their capacity to meet minimum run-time requirements, the Commission noted in Order No. 841 that:

> [T]his requirement would allow a 10MW/20MWh electric storage resource to offer 5MW of capacity into a capacity market with a 4-hour minimum run- time because that is the maximum output that the resource can sustain for the duration of the minimum run-time. Absent the opportunity to de-rate its capacity, the 10MW/20MWh electric storage resource would not be able to participate in that capacity market, *despite its ability to reliably provide 5MW of capacity for the duration of the minimum run-time.*[25]

Therefore, in putting forth this example, the Commission implicitly acknowledged in Order No. 841 that an ESR with a 4-hour duration requirement (*i.e.* 4-hour minimum run time) is able to "reliably provide" capacity, at least in some instances.

Based on the foregoing, in order to comply with both the letter and spirit of Order No. 841, the onus is on PJM to demonstrate why it must establish a duration requirement for non-hydro ESRs that is significantly longer than any similar duration requirement established for such resources by any other Commission-jurisdictional RTO, and that would contradict the Commission's observation in Order No. 841 that ESRs are, at least in some instances, able to "reliably provide" capacity while being subject to a 4-hour duration requirement. While PJM attempts to do this through its compliance filing and the affidavit of Jeff Bastian ("Bastian Affidavit"), PJM's attempt falls woefully short.

In her affidavit, Dr. Nicholson explains in depth how PJM failed to justify imposing the 10-hour requirement on non-hydro ESRs in the PJM Compliance Filing. As explained in the Nicholson Affidavit:

- In seeking to justify the 10-hour duration requirement, PJM did not even address the critical question of what the minimum amount of time a non-hydro ESR should be required to operate continuously in order to maintain the required level of reliability in

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[25] *See* Order No. 841 at P 93 (emphasis added).

PJM given the expected participation level of ESRs in the PJM capacity market and the unique operating characteristics of ESRs.[26]

- The 2010 study of Limited Demand Response Resources (the "2010 Demand Response Study") relied upon by PJM to support its position does not support applying the 10-hour duration requirement to non-hydro ESRs because, *inter alia*: 1) the study examined the reliability implications of Demand Response resources with specific operational constraints (*i.e*., the seasonal, hourly, interruption, and duration constraints), and a non-hydro-ESR is a fundamentally different to a demand response resource;[27] and 2) the 2010 Demand Response Study is based on inputs that are out-of-date and assumptions that are not appropriate to analyze the reliability implications of non-hydro ESRs.[28]

- PJM's analysis assumes that non-hydro ESRs will constitute 8.5% of peak load in its capacity market and analyzes the reliability impacts at this level of non-hydro ESR penetration. However, to date no non-hydro ever offered into the RPM. As such, the current non-hydro ESR participation level in the RPM is zero. The PJM system currently has approximately 700 MW of battery storage that participates in the PJM regulation market and 817.2 MW of battery storage in the PJM interconnection queue. It is not reasonable to assume that all of the battery storage in the interconnection queue will be built, but even if it is, and the queue projects are in service fairly quickly, PJM would have approximately 1,517.2 MW of installed non-hydro ESR in the near term. As such, there is no reasonable basis to assume that non-hydro ESR will constitute 8.5 percent of the projected peak load.[29]

- A recent study about Limited Energy Capability Resources (LECR) (the "2018 LECR Study") relied upon by PJM is not even publicly available. However, based on a presentation describing the 2018 LECR Study, the 2018 LECR Study discussed the concept of "equivalent duration," defined as the amount of energy (in MWh) generated during the peak period divided by the maximum output (in MW) an LECR is assumed to generate based on the assumed penetration level and charge and discharge patterns in the 2018 LECR Study. Notably, the equivalent duration figure discussed in the September 2018 LECR Presentation *is not the same as PJM's continuous duration requirement*. This is because the continuous duration requirement refers to a resource's ability to generate a certain minimum level of output (measured in MW) for a certain period of time (measured in units of time). By contrast, the concept of equivalent duration in the September 2018 LECR Presentation measures the duration of time over which an LECR is assumed to generate electricity during the peak period based on the assumed load profile, LECR penetration level, and LECR charge and discharge patterns. Accordingly, the second study relied upon by PJM to justify the 10-hour duration requirement is not

[26] *See* Nicholson Affidavit at P 2-3.

[27] *See id.* at P 4-5.

[28] *See id.* at P 6-8.

[29] *See id.* at P 10.

> only unavailable to the public, but also apparently analyzes a completely different metric than the continuous duration requirement.[30]

For these reasons, and the reasons further specified in the Nicholson Affidavit, PJM has failed to justify imposing the 10-hour duration requirement on non-hydro ESRs from a technical perspective, and failed to show that it is necessary to preserve the reliability of PJM's bulk power system.

C. The 10-Hour Requirement Is Not Supported By Any Reasonable Interpretation of PJM's Governing Documents or Manuals.

PJM's position that utilizing the 10-hour duration requirement when determining an ESR's capacity value is "consistent with the RAA,"[31] and thus their implicit position that it is authorized by its current filed rate is patently wrong. However, further examination of PJM's governing documents and manuals reveals that using the 10-hour duration requirement in this manner is clearly not supported under any reasonable interpretation of PJM's governing documents or manuals.

1. A Straightforward Reading of Manual 21 and PJM's Governing Documents Shows That The 10-Hour Requirement Has Nothing to Do With Calculating ESRs' Capacity Value.

When interpreting a tariff, the first step is to determine whether the plain meaning of the tariff is clear on its face.[32] Here, there is no language in PJM's Tariff or other governing documents that clearly and specifically addresses the duration requirement that should be used to measure an ESRs' capacity value. As a result, PJM puts forth an interpretation of the RAA and associated manuals which is intended to justify the 10-hour duration requirement's application to

[30] *See id.* at P 11-15.

[31] *See* PJM Compliance Filing at 20.

[32] *See e.g. Seminole Elec. Coop., Inc. v. Fla. Power & Light Co*., 139 FERC ¶ 61,254, at P 31 (2012).

calculating ESRs' capacity value.[33] PJM's analysis takes up approximately one page of the PJM Compliance Filing, and PJM's textual analysis concludes by stating:

> [e]choing RAA Schedule 9's reference to the "ability of units to maintain output at stated capability over a specified period of time[,]" Manual 21 has for many years stated that the "number of hours of continuous operation [that is] commensurate with PJM load requirements [is] specified as 10 hours."[34]

Put another way, PJM essentially argues that the RAA authorizes PJM to rely on implementing technical language in Manual 21, Section 2.1(13)[35] to impose the 10-hour duration requirement, which is the *only* place in PJM's governing documents or manuals where the 10-hour duration requirement is specified. However, a closer look at Manual 21 reveals that the language that PJM references that purportedly describes the 10-hour duration requirement has nothing to do with measuring the capacity value of an ESR.

PJM Manual 21 is entitled "Rules and Procedures for Determination of Generating Capability," which is a separate manual from PJM Manual 18, the main PJM manual where technical requirements related to participating in PJM's capacity market are maintained.[36] Further, Manual 21, Section 2.1 is entitled "Net Capability." The introduction of Manual 21 describes the purpose of Manual 21 and the context in which "Net Capability" is used by PJM, stating in relevant part that:

> **Net Capability** of generating units installed in, scheduled for installation in or transacted into the PJM Control Area is required for planning and reporting

[33] *See* PJM Compliance Filing at 21-22.

[34] *See id.* at 22 (citations omitted).

[35] *See PJM Manual 21: Rules and Procedures for Determination of Generating Capability*, PJM Interconnection, L.L.C., Section 2.1(13) (rev. 12, Jan. 1, 2017), https://pjm.com/-/media/documents/manuals/m21.ashx ("Manual 21").

[36] *See PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., (rev. 41, Jan. 1, 2019), https://www.pjm.com/-/media/documents/manuals/m18.ashx ("Manual 18").

purposes and for use in accounting for deficiencies of a Party to obligations under the Operating and Reliability Assurance Agreements of PJM.

. . .

The rules and procedures recognize the difference in types of generating units involved as resources within the PJM Capacity Markets processes and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, system operating policies.[37]

Further, based on the Clean Energy Entities' review, "Net Capability" is not a defined term in any of PJM's governing documents, although PJM Manual 21, Section 2.1 defines Net Capability as:

[T]he number of megawatts of electric power which can be delivered by an electric generating unit without restriction by the owner under the conditions and criteria specified herein and shall be determined as the gross output of the unit less power used for unit auxiliaries and other station use required for electrical generation and any power required to serve host process load.[38]

To summarize the foregoing sections of Manual 21, "Net Capability" generally refers to the amount of megawatts of electric power that can be delivered without restriction by a particular resource, subject to certain limitations of various classes of resources.

Next, Manual 21, Section 2.1 goes onto explain how the "Net Capability" for several different types of resources are calculated. The Net Capability for ESRs (referred to as "storage" in Manual 21) is calculated in the following manner, depending on whether the ESR is hydro or non-hydro:

The determination of Net Capability for a hydro (with storage and/or pooling capability) or pumped storage unit shall recognize the head available giving proper consideration to operating restrictions and the reservoir storage program during a normal cycle at the expected time of the PJM peak.

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[37] *See* Manual 21, About This Manual: Purpose.

[38] *See* PJM Manual 21, Section 2.1(1).

> The determination of Net Capability for a storage (non-hydro) unit shall recognize the MWH energy available, giving proper consideration to other market activities for which the storage (non-hydro) unit may be committed during the expected time of the PJM peak.[39]

Finally, Manual 21, Section 2.1(13), the provision cited by PJM as establishing the 10-hour duration requirement when calculating ESRs' capacity value, states *in full*:

> All or any part of a unit's capability that can be sustained for a number of hours of continuous operation commensurate with PJM load requirements, specified as 10 hours, *shall be considered as unlimited energy capability*. All or any part of a unit's capability shall be considered as limited energy capability only for those periods in which it does not meet the foregoing criteria for sustained operation. Such limited energy capability will be used to meet the energy requirements of PJM and depending on the extent to which it meets these requirements such capability may be reduced as provided in Schedule 9 of the Reliability Assurance Agreement (RAA).[40]

The Clean Energy Entities have copied these relevant provisions of Manual 21 to illustrate several important points for the Commission's consideration:

- the general description of "Net Capability" in the introduction of Manual 21 does not in any way describe how Net Capability is used to calculate any resource's capacity values;
- the specific references to ESRs in Manual 21, Sections 2.1(6) and (7) (which were not cited at all by PJM) make no mention of how ESRs' capacity value is calculated; and
- *nowhere* in Manual 21, Section 2.1(13), is there *any mention* of how a resource's Net Capability impacts the calculation of a resource's capacity value.

Most importantly, all that Manual 21, Section 2.1(13) specifies with respect to the 10-hour requirement is that "[a]ll or any part of a unit's capability that can be sustained for a number of hours of continuous operation commensurate with PJM load requirements, specified as 10

[39] *See id.* at Sections 2.1(6), (7).

[40] *See id.* at Section 2.1(13) (emphasis added).

hours, shall be considered as *unlimited energy capability*." Tellingly, PJM did not provide the full citation to Manual 21, Section 2.1(13) in the PJM Compliance Filing, and did not quote the crucial language stating that the 10-hour duration requirement only pertains to qualifying resources' "unlimited energy capability."[41] This appears to be the case because, based on the Clean Energy Entities' review, "unlimited energy capability" is not a defined term in *any* of PJM's governing documents, and further, aside from the reference in Manual 21, Section 2.1(13), it is not even *repeated* in any of PJM's governing documents, Manual 21, or Manual 18.

Given this, it is unclear precisely what, if any, practical meaning can be attributed to "unlimited energy capability" within PJM's governing documents and manuals. However, what *is clear* is that the 10-hour duration requirement in Manual 21, Section 2.1(13) only defines when a unit is capable of providing "unlimited energy capability," but "unlimited energy capability" is not in any way related to calculating ESRs' (or any resource's) capacity value per the plain language of Manual 21 and PJM's governing documents. Therefore, unless PJM can explain otherwise, it appears that the *key language* that PJM points to in order to justify utilizing the 10-hour duration requirement when calculating ESRs' capacity value apparently has *nothing* to do with actually calculating ESRs' capacity value.

Based on the foregoing analysis, contrary to PJM's claims, PJM cannot rely upon the general provisions of the RAA and Manual 21, Section 2.1(13) to justify imposing the 10-hour duration requirement on non-hydro ESRs.

2. Imposing the 10-Hour Requirement As Part of Valuing ESRs' Capacity Value Would Be A Violation of PJM's Filed Rate.

[41] *See* PJM Compliance Filing at 22 (PJM only stated that "Manual 21 has for many years stated that the 'number of hours of continuous operation [that is] commensurate with PJM load requirements [is] specified as 10 hours.'").

PJM's statements that it currently uses the 10-hour duration requirement to determine the capacity value of ESRs, and its rationale for doing so[42] does not negate the fact that PJM's current filed rate and manuals do not permit the practice.

It is well-established precedent that "[t]he filed rate doctrine prohibits a public utility from charging rates for its services other than those properly filed with the Commission."[43] Further, the Commission's "rule of reason" governs which portions of the "infinitude" of practices affecting PJM's rate needs be filed with the Commission under the FPA, and which can be put in documents not filed with the Commission, such as manuals.[44] The duration requirement for qualifying ESRs' capacity value would seem to be a practice that "affect[s] rates and service *significantly*,"[45] and therefore would warrant being specified in PJM's governing documents, which it is not. However, even assuming *arguendo* that the 10-hour duration requirement is appropriate for a manual rather than one of PJM's governing documents (a point which the Clean Energy Entities take no position on at this time),[46] PJM cannot claim that the 10-hour duration requirement is supported by its manuals for the reasons previously described in Section II.C.1.

Accordingly, given that PJM's governing documents do not contain language pertaining to the 10-hour duration requirement, and because PJM's manuals do not permit using the 10-

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[42] *See e.g.* PJM Compliance Filing at 22-27; *see generally* Bastian Affidavit.

[43] *See e.g. Southwest Power Pool, Inc.*, 149 FERC ¶ 61,050, at P 26 (2014).

[44] *See e.g. City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) (*City of Cleveland*); *California. Indep. Sys. Operator*, 122 FERC ¶ 61,271, P 16 (2008).

[45] *See City of Cleveland* F.2d at 1376.

[46] *See e.g. ISO New England, Inc.*, 137 FERC ¶ 61,112, at P 19 (2012) ("system operator[s] may rely on [their] manuals to implement the filed rate and provide technical details, in light of the multitude of occasions in tariff administration that require the exercise of technical or operational expertise.").

hour duration requirement to determine a non-hydro ESRs' capacity value, PJM has no legal basis for continuing this practice.

Moreover, aside from the fact that PJM failed to justify the 10-hour requirement for the reasons set forth in Section II.B and the Nicholson Affidavit, PJM cannot seek to obtain the Commission's authorization to implement this practice – one which to the Clean Energy Entities' knowledge has *never* been reviewed by the Commission – in the context of submitting its compliance filing given the Commission's holding stating "[t]o the extent that an RTO/ISO seeks to revise its tariff provisions setting forth the technical requirements for providing any specific wholesale service, the RTO/ISO may propose such revisions to its tariff through a separate FPA section 205 filing."[47]

D. PJM's Tariff and the Commission's Proceeding in Docket No. ER15-623-000 Demonstrate That ESRs' Capacity Value Should Be Measured Over "Peak-Hour Periods."

While the RAA and Manual 21 do not justify imposing a 10-hour duration requirement on ESRs for the purposes of calculating their capacity value, in August 2018, the Energy Storage Association ("ESA") outlined how PJM's governing documents, and key rulings by the Commission and associated filings made by PJM in Docket No. ER15-623-000 (the "Capacity Performance Proceeding"), show that PJM's governing documents support determining ESRs' capacity value over "peak-hour periods."[48] The Clean Energy Entities summarize many of the issues discussed in the ESA Presentation, although offer their own independent analysis and proposed path forward.

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[47] *See* note 17, *supra*.

[48] Energy Storage Association, "Capacity Storage Duration Requirements", PJM MIC Special Session (Aug. 3,2018), available at https://www.pjm.com/-/media/committees-groups/committees/mic/20180803-special-energy/20180803-item-04a-esa-capacity-storage-resource-duration.ashx ("ESA Presentation").

In PJM's initial filing that proposed the Capacity Performance construct, PJM noted that the proposal was "far less prescriptive on the eligibility requirements for Capacity Performance Resources" compared to earlier proposals that were vetted by PJM's stakeholders but ultimately not submitted for the Commission's consideration.[49] PJM further stated that "the tariff changes in this filing are not overly prescriptive on qualification or eligibility requirements of a Capacity Performance Resource."[50] Importantly, nowhere in the PJM Initial Capacity Performance Filing did PJM establish stringent requirements for calculating any resource's capacity value, nor did it mention the purported 10-hour duration requirement for calculating ESRs' capacity value in Manual 21, Section 2.1(13).

Next, in its February 14, 2015 Answer[51] made in response to stakeholder comments on the PJM Initial Capacity Performance Filing, PJM "confirm[ed] the methodology for calculating Intermittent/*Storage*/DR/EE capacity values as expressed in FAQ 122, and PJM commits to incorporating this methodology in its manuals."[52] As described by PJM therein:

> In response to FAQ 122, PJM posted a spreadsheet showing how a 50 MW PC solar photovoltaic ("PV") resource could offer 15 MW as a Capacity Performance Resource. The spreadsheet provides an example calculation for this approach based on the probabilistic expectation of the solar facility's hourly average output on a monthly basis. The spreadsheet output of the resource is averaged over the reasonably expected hours in the summer and the winter when emergency conditions could occur on the PJM system. For the purposes of this calculation, those hours are defined as hours six through nine and eighteen through twenty-one

[49] *See* Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA"), Docket No. ER15-623-000, at 21 (Dec. 12, 2014) ("PJM Initial Capacity Performance Filing").

[50] *See id.* at 22.

[51] Answer of PJM Interconnection, L.L.C., Docket No. ER15-623-000, at 23 (Feb. 14, 2015) ("February 14, 2015 Answer").

[52] *See id.* at 23 (emphasis added).

> in the months of January and February, and hours fifteen through twenty in the months of June, July, and August.[53]

Notably, once again, PJM made no mention of the 10-hour duration requirement in Manual 21, Section 2.1(13) in its response.

On June 9, 2015, the Commission issued an order largely approving PJM's Capacity Performance construct but also ordered PJM to revise its governing documents with respect to several issues in a compliance filing.[54] With respect to measuring ESRs' capacity value, the Commission held the following:

> We also find PJM's proposal, as clarified in its answer, to permit . . . Capacity Storage Resources . . . [to] offer as stand-alone Capacity Performance Resources to be just and reasonable. Therefore, we accept this aspect of PJM's proposal, subject to PJM submitting tariff revisions clarifying that, as PJM states in its answer, Capacity Storage Resources . . . may submit stand-alone Capacity Performance sell offers in a MW quantity consistent with their average expected output during *peak-hour periods*.[55]

In response to the Commission's directive, PJM submitted conforming governing document revisions in a compliance filing, noting that it amended Tariff, Attachment DD, Section 5.6.1(h) in order to, *inter alia*, "confirm that resources of the listed resource types can submit Capacity Performance Resource offers 'in a MW quantity consistent with their average expected output during peak-hour periods.'"[56] Once again, PJM made no mention of the 10-hour duration requirement in Manual 21, Section 2.1(13), nor did it mention that ESRs'(or any

[53] *Id.* at 21 (emphasis added, citations omitted).

[54] *See generally PJM Interconnection, L.L.C., et al.*, 151 FERC ¶ 61,208 (2015) ("June 9, 2015 Order").

[55] *See id*. at P 100 (emphasis added).

[56] PJM Compliance Filing, Docket No. ER15-623-004, at 5 (Jul. 9, 2015) ("PJM Capacity Performance Compliance Filing").

resource's) capacity value was to be calculated in accordance with its "unlimited energy capability" referenced in Manual 21, Section 2.1(13).

The PJM Capacity Performance Compliance Filing was accepted by the Commission, and as a result, Tariff, Attachment DD, Section 5.6.1(h) now states in relevant part that:

> For the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during *peak-hour periods*.[57]

Accordingly, based on both the plain language and history of Tariff, Attachment DD, Section 5.6.1(h), it is clear that Sell Offers (defined as "an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction"[58]) from Capacity Storage Resources are submitted "in a MW quantity consistent with their average expected output during *peak-hour periods*,"[59] and not in accordance with the 10-hour duration requirement in Manual 21, Section 2.1(13) (which as discussed addresses only qualifying ESRs' "unlimited energy capability").

Unfortunately, PJM's governing documents and manuals do not explicitly define what the "peak-hour period" for ESRs referenced in Tariff, Attachment DD, Section 5.6.1(h) is. "Peak-hour period" is not a defined term in PJM's governing documents, and PJM's governing documents and manuals do not describe specific "peak hours" or a "peak-hour period" that should be used when calculating an ESR's capacity value. However, Manual 21, Appendix B defines "Peak Hours" for wind and solar capacity resources as "those ending 3, 4, 5, and 6 PM

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[57] Tariff, Attachment DD, Section 5.6.1(h) (emphasis added).

[58] *See* Tariff, Definitions.

[59] *See* Tariff, Attachment DD, Section 5.6.1(h) (emphasis added).

Local Prevailing Time",[60] (a 4-hour period). Given this language, and based on the fact that Tariff, Attachment DD, Section 5.6.1(h) states that Sell Offers into PJM's capacity market from Capacity Storage Resources, Intermittent Resources, Demand Resources and Energy Efficiency Resources should be submitted "in a MW quantity consistent with their average expected output during peak-hour periods,"[61] the most logical interpretation of PJM's currently effective governing documents and manuals is to conclude that the "peak-hour period" for Capacity Storage Resources (which includes non-hydro ESRs) is four hours.

III. REQUESTED ACTION

Based on the foregoing analysis in Section II.C, it is clear that the 10-hour duration requirement that PJM has been using to calculate non-hydro ESRs' capacity value is not supported by any reasonable interpretation of PJM's governing documents or manuals, and for the reasons set forth in Section II.B and the Nicholson Affidavit, PJM failed to support the 10-hour duration requirement's application to non-hydro ESRs from a technical and reliability perspective. Therefore, allowing the 10-hour duration requirement to be used when calculating non-hydro ESRs' capacity value in the upcoming August 2019 BRA would be patently unjust and unreasonable, and completely unsupported from both legal and technical perspectives. Further, while PJM could attempt to justify the 10-hour requirement by submitting a separate FPA section 205 filing, it is extremely unlikely that such a proposal could be adequately vetted and discussed with PJM's stakeholders, submitted to the Commission, and approved by the

[60] *See* Manual 21, Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources.

[61] *See* Tariff, Attachment DD, Section 5.6.1(h).

Commission before May 1, 2019, which is when PJM posts planning parameters ahead of the August 2019 BRA.[62]

Accordingly, the Clean Energy Entities request that the Commission reject PJM's use of the 10-hour duration requirement when determining the capacity value of non-hydro ESRs, and order PJM to file governing document changes that utilize a 4-hour duration requirement when calculating non-hydro ESRs' capacity value. This is appropriate because as discussed in Section II.C, the most logical interpretation of PJM's currently effective governing documents and manuals is to conclude that the "peak-hour period" applicable to non-hydro ESRs is four hours, and therefore the duration requirement that should be utilized when calculating the capacity value for non-hydro ESRs is also four hours.

Alternatively, if the Commission disagrees with this interpretation of PJM's governing documents and manuals and instead concludes that PJM's currently effective governing documents and manuals are ambiguous as to what the proper duration requirement for non-hydro ESRs should be, the Clean Energy Entities request that the Commission order PJM to utilize a 4-hour duration requirement when calculating non-hydro ESRs' capacity value on an interim basis. Utilizing a 4-hour duration requirement as an interim solution is necessary because otherwise PJM will presumably apply its unauthorized 10-hour duration requirement to ESRs in the upcoming August 2019 BRA, thus unjustly and unreasonably discounting ESRs' capacity value. Further, using a 4-hour duration requirement as an interim solution is appropriate and just and reasonable because: 1) it is the *maximum* duration requirement for ESRs permitted by other Commission-jurisdictional RTOs, meaning that ESRs offering into PJM's capacity market will be treated in accordance with the most conservative assumptions for ESRs employed by other

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[62] *See e.g.* 2019 BRA Order at P 4 n. 6 (recognizing that PJM proposed post BRA planning parameters for the August 2019 BRA on May 1, 2019. PJM's request was granted by the Commission.

RTOs,[63] and 2) as previously noted, the Commission implicitly acknowledged in Order No. 841 that an ESR with a 4-hour duration requirement is able to "reliably provide" capacity, at least in some instances.[64] Following the submittal of interim tariff provisions effective for the August 2019 BRA, the Clean Energy Entities also request the Commission to direct PJM and its stakeholders to work together to perform a reliability study to determine the appropriate duration requirement for non-hydro ESRs, and to submit governing document revisions that will establish non-interim duration requirements for non-hydro ESRs.[65] PJM should then propose tariff revisions supported by the reliability study in a separate FPA section 205 filing.

Finally, the Clean Energy Entities request that the Commission issue an order in the above-captioned proceeding granting the relief sought in this Protest by March 15, 2019 at the latest, and order PJM to file governing document revisions implementing the 4-hour duration requirement for ESRs on an interim basis by April 22, 2019, at the latest. Commission action within this requested timeline will provide market certainty and also enable ESRs to offer capacity into the 2019 BRA and beyond in a manner that properly accounts for their capacity value in accordance with Order No. 841.

IV. CONCLUSION

For the aforementioned reasons, the Clean Energy Entities request that the Commission consider its Protest herein.

Respectfully submitted,

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[63] *See* Section II.B, *supra*.

[64] *See* note 25, *supra*.

[65] The Clean Energy Entities take no position at this time as to what the non-interim duration requirement for non-hydro ESRs should be. If the Commission grants the Clean Energy Entities' requested relief, the Clean Energy Entities and its members look forward to working with PJM and other stakeholders on developing a non-interim duration requirement for non-hydro ESRs based on careful and considered analysis through the requested reliability study.

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Attachments: Attachment A: Prepared Testimony of Emma L. Nicholson

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 7th day of February 2019.

/s/ Gene Grace

Gene Grace

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	ER18-469-000

PREPARED TESTIMONY OF
EMMA L. NICHOLSON
ON BEHALF OF AMERICAN WIND ENERGY ASSOCIATION

Q: Please state your name, position, and business address.

A: My Name is Emma L. Nicholson. I am a Senior Project Manager at Concentric Energy Advisors, Inc. My business address is 1300 19th Street, NW, Suite 620, Washington DC 20036.

Q. Please Describe your professional experience and educational background.

A. I am an economist with over 15 years of experience in the electric utility industry, focusing on wholesale electricity, ancillary services, and capacity market design. I also have experience in competition analysis, market power mitigation, and retail rate design. Prior to joining Concentric Energy Advisors, I was an economist at the Federal Energy Regulatory Commission's ("FERC" or "Commission") Office of Energy Policy and Innovation, where, among other things, I played a key role in the Commission's Price Formation effort, the May 2017 technical conference on integrating state policies with wholesale energy and capacity markets, and advised the Commission and senior staff on numerous filings related to RTO/ISO energy, ancillary services, and capacity market design issues. I also served as a technical advisor to then Chairman Norman Bay. Prior to joining FERC, I was a consultant at Exeter Associates, Inc. where, among other things, I testified on retail cost allocation and rate design matters before state public utilities commissions in Indiana, Pennsylvania, and Rhode Island. I have an M.A. and Ph.D. in Economics from Georgetown University and a B.A. in Economics and Government from the University of Maryland at College Park.

Q. What is the purpose of your testimony?

A. The American Wind Energy Association asked me to review and assess the evidence PJM, Interconnection, L.L.C. ("PJM") put forth in its compliance filing to Order No. 841, to support PJM's qualification requirement for storage resources.[1] Specifically, calculating the quantity of capacity an electric storage resource that is not a hydroelectric pumped-storage electric storage resource ("non-hydro ESR") can offer into PJM's capacity market on that resource's ability to generate electricity for ten continuous hours ("duration requirement").[2]

Q. Please summarize your conclusions.

A. Based on my analysis of the PJM 841 and the evidence available in this proceeding to date (Docket No. ER19-469-000), I find that PJM has not supported the 10-hour duration requirement. The studies PJM cites as support for the non-hydro ESR duration requirement do not in fact support the duration requirement because the studies did not analyze the correct questions and are based on either

[1] PJM Interconnection, L.L.C., Order No. 841 Compliance ESR Markets and Operations Proposal, Docket No. ER19-469-000, filed December 3, 2018 ("PJM Transmittal").
[2] *See e.g. id.* at 10-11, 18-29.

outdated information or unreasonable assumptions. PJM also sought to support the duration requirement by drawing a distinction between non-hydro ESRs and intermittent resources, which also fails to support the specific duration requirement (i.e., 10 hours) PJM would apply to non-hydro ESRs.

Q. **What questions should PJM have analyzed or considered to determine a reasonable duration requirement for non-hydro ESR resources?**

A. To determine a reasonable duration requirement to qualify capacity of non-hydro ESRs, PJM should have analyzed the following question: what is the minimum amount of time a non-hydro ESR should be required to operate continuously in order to maintain the required level of reliability in PJM given the given the expected participation level of ESRs in the capacity market and the unique operating characteristics of ESRs. As I discuss further below, PJM did not present any evidence that it performed a study that attempted to answer this specific question.

Q: **What studies does PJM cite to support the 10-hour duration requirement for ESRs?**

A: PJM cites two studies to support applying the10-hour duration requirement to non-hydro ESRs: a 2010 study of Limited Demand Response Resources ("2010 Demand Response Study") and a 2018 Limited Energy Capability Resource study ("2018 LECR Study"). PJM relies more heavily on the 2010 Demand Response Study and this study is actually available for the Commission and other stakeholders to review and assess based on a reference PJM provided in its compliance filing. I have reviewed and assessed the 2010 Demand Response study. PJM did not provide a reference that enabled stakeholders to review and assess the 2018 LECR Study and I was unable to locate it independently. However, as discussed below, I reviewed a presentation about the study that PJM staff presented to stakeholders. I will discuss the assumptions, methodology, and results of the two studies, and assess whether the studies support applying a 10-hour duration requirement to non-hydro ESRs.

Q: Please describe the 2010 Demand Response Study

A: PJM staff, under the direction of Thomas A. Falin, Manager of Resource Adequacy and Planning, prepared a study to determine the maximum quantity of capacity in megawatts ("MW") that certain demand response resources with limited availability could be used to meet PJM's resource adequacy requirement in the Reliability Pricing Model ("RPM") without increasing the expected loss of load probability by more than 10 percent.[3] Mr. Falin provided a summary of the results of the 2010 Demand Response Study and the study itself in an affidavit accompanying a PJM proposal (filed in December 2010) to add a new capacity demand response resource category – Extended Summer Demand Response.[4] I have included a copy of Mr. Falin's Affidavit and the 2010 Demand Response Study as Exhibit 1 to this affidavit. The 2010 Demand Response Study, released in May 2010, was used as the basis to determine the maximum quantity of capacity from "Limited Demand Resources" that PJM could procure in its

[3] Thomas A Failin Affidavit, Docket No ER18-11-000, filed December 2, 2010, at 4 ("Falin Affidavit.").
[4] Failin Affidavit. at 2. Note that this demand response resource category was phased out with the implementation of Capacity Performance. See PJM Transmittal at note 60.

capacity market – referred to as the Reliability Pricing Model ("RPM") – while maintaining an acceptable level of reliability. The study established a "Reliability Target" for the total quantity of Limited Demand Resources procured in the RPM that Mr. Falin defined as the "maximum amount of Limited Demand Resources that can be reliability procured" in the RPM to meet the reliability requirement.[5] Mr. Falin explained that it was necessary to determine such a target for Limited Demand Response resources because of the limitations associated with such resources. Specifically, PJM could only call on Limited Demand Resources to provide capacity (which was provided by reducing load in response to instructions from PJM operators) subject to the following pre-determined constraints: (1) *seasonal constraint*: only available during the summer months of June through September; (2) *hourly constraint*: only available during certain hours of the day, (3) *interruption constraint*: only available up to 10 times per summer; and (4) *duration constraint*: only available for a maximum of six consecutive hours.[6] The 2010 Demand Response Study analyzed the reliability implications of Limited Demand Resources by asking two questions: 1) what is the level (in MW) of Limited Demand Resources cleared in the RPM that would cause an unacceptable risk that PJM would have to call on such resources more than 10 times in a summer season and; 2) assuming the level determined in response to question 1,

[5] Falin Affidavit at 4. The Reliability Target is premised on the assumption that PJM procures a quantity of capacity in the RPM equal to the reliability requirement.
[6] Falin Affidavit. at 1-2.

how many hours must Demand Resources interrupt their loads when called upon by PJM to be effective in reducing peak demand when needed.[7]

Q: What did the 2010 Demand Response Study conclude?

A: The 2010 Demand Response Study concluded that PJM could be confident, to a 90 percent degree of certainty, that it would not need to call on Limited Demand resources more than 10 times in one summer provided that such resources constituted no more than 8.5 percent of the projected peak load.[8]

Q: What methodology did the 2010 Demand Response Study employ?

A: The 2010 Demand Response Study involved a sophisticated probabilistic reliability study with multiple steps. To determine the Reliability Target for Limited Demand Response resources, PJM examined the interruption constraint (up to ten times per summer) and the duration constraint (six consecutive hours) separately. To examine the interruption constraint, PJM estimated 418 load forecast scenarios and applied them to a forecast of 20 peak load days in the 2013/14 delivery year, which were expected to occur in the summer of 2013. The 2013/14 delivery year load forecast was developed in 2009. These 418 scenarios were used to generate a distribution of loads on days with the highest forecasted loads, which PJM used to estimate the probability that the PJM system would be unable to meet the forecasted load plus the required 15.3 percent reserve margin.[9]

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[7] Falin Affidavit at 2.

[8] Falin Affidavit at 2. This conclusion also assumed that the RPM successfully procured a quantity of capacity equal to the required installed reserve margin.

[9] Falin Affidavit, Exhibit 1 at 3-5.

Q: How did the 2010 Demand Response Study estimate the reliability implications of Limited Demand Resources?

A: Based on the 418 load scenarios and load forecasts for the 20 peak days during the 2013 summer and the expected availability of other PJM capacity resources, the 2010 Demand Response Study estimated the probability that Limited Demand Resources would need to be called ten times or fewer (*i.e.*, that PJM could use the resources without violating the interruption constraint) in the summer of 2013.[10] PJM then examined how the probability of failing to maintain the required reserve margin would change as the quantity of Limited Demand Response resources procured in the RPM increased. This probabilistic analysis found that the higher the quantity (measured as a percentage of forecasted peak load) of Limited Demand Response that cleared the RPM, the higher the likelihood that a Limited Demand Resource would violate the interruption constraint (*i.e.*, be called on more than 10 times during the summer) and thus potentially raise a reliability concern. The 2010 Demand Response Study stated that "engineering judgment" was used to select an acceptable upper bound – or Reliability Target – on the quantity of Limited Demand Response resources procured in the RPM.[11] The study found that 8.5 percent of the projected peak load was reasonable Reliability Target because this penetration level represented the point at which there was a 10 percent probability that PJM would need to call on a Limited Demand Resource

[10] PJM presented the probabilistic analysis in the form of a function that measured how the expected probability that PJM would have to call on a Limited Demand Response Resource to provide capacity ten times or fewer during the summer would change as the quantity of such resources procured the RPM increased. *See* Falin Affidavit. Exhibit 1, Figures 2 and 3.

[11] Falin Affidavit, Exhibit 1 at 8.

more than ten times (*i.e.*, that there was a ten percent chance that the interruption constraint would bind).[12] The 2010 Demand Response Study conducted a separate analysis of the six-hour duration constraint associated with Limited Demand Resources. This part of the study assumed an 8.5 percent penetration level for Limited Demand Resources, which was based on the conclusions of the interruption constraint analysis described above. The objective of the duration constraint analysis was to ensure that PJM's Demand Response program reduced the projected daily peak by the full amount of the Demand Response enrolled and to ensure that the daily peak still fell within the Demand Response interruption window.[13] The 2010 Demand Response study analyzed historical peak load days from the 2005-2009 period and concluded, based on an assumed 8.5 penetration, that the duration requirement should be increased from six to ten hours to achieve this objective.[14]

Q: Do the results of the 2010 Demand Response Study support PJM's 10-hour duration requirement for non-hydro ESRs

A: No. The results of the 2010 Demand Response Study are not transferrable to non-hydro ESRs because, as I described above, the study examined the reliability implications of Demand Response resources with specific operational constraints (i.e., the seasonal, hourly, interruption, and duration constraints). A non-hydro-ESR is a fundamentally different to a demand response resource. A non-hydro

[12] Falin Affidavit, Exhibit 1 at 8.
[13] Falin Affidavit, Exhibit 1 at 9-10.
[14] Falin Affidavit, Exhibit 1 at 10-11.

ESR is not a load, and unlike a demand response resource, non-hydro ESRs can provide capacity by either generating electricity or by withdrawing electricity from the system, depending on its state of charge and on operator instructions. While non-hydro ESRs not paired with other resources are likely to be subject to a duration constraint that will vary by facility, such resources are not typically subject to the seasonal, hourly, or interruption constraints associated with the Limited Demand Response resources PJM analyzed in the 2010 Demand Response Study. Non-hydro ESRs can also be expected respond more quickly than the Limited Demand Response resources examined in the 2010 Demand Response Study, which had to be notified several hours ahead of time.[15]

Q: **Apart from analyzing a different class of resource, are there other reasons that the results of the 2010 Demand Response Study do not support PJM's duration requirements for ESRs?**

A: Yes, the 2010 Demand Response Study is based on inputs that are out-of-date and assumptions that are not appropriate to analyze the reliability implications of non-hydro ESRs. With respect to the inputs, the probabilistic analysis to determine the Limited Demand Resource penetration level above which the interruption constraint would bind was based on the distribution of projected loads for the summer of 2013 using forecasts developed in 2009 and 2010. Additionally, the portion of the 2010 Demand Response Study that examined the duration constraint of Limed Demand Resources assumed 8.5% penetration level.[16] PJM has not

[15] Falin Affidavit, Exhibit 1 at 7.
[16] Falin Affidavit, Exhibit 1, at 10.

demonstrated that the key inputs employed in the 2010 Demand Response Study, some which are at least ten years old, reflect current conditions in PJM. Nor has PJM shown that 8.5 percent is a reasonable penetration level to assume for non-hydro ESR participation in the RPM.

Q: Is it reasonable to assume that non-hydro ESRs will constitute 8.5 percent of peak load in the RPM based on current or expected market conditions?

A: No. PJM states that to date, no non-hydro ESR resource ever offered into the RPM.[17] As such, the current non-hydro ESR participation level in the RPM is zero. The PJM system currently has approximately 700 MW of battery storage that participates in the PJM regulation market[18] and 817.2 MW of battery storage in the PJM interconnection queue.[19] It is not reasonable to assume that all of the battery storage in the interconnection queue will be built, but even if it is, and the queue projects are in service fairly quickly, PJM would have approximately 1,517.2 MW (i.e., 700 MW + 817.2 MW) of installed non-hydro ESR in the near term. As such, there is no reasonable basis to assume that non-hydro ESR will constitute 8.5 percent of the projected peak load - which would have amounted to approximately 12,977 MW - in the most recent BRA held for the 2021/22 delivery year.[20]

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[17] PJM Transmittal at 18-19.

[18] PJM Transmittal at 38.

[19] Monitoring Analytics, *PJM Quarterly State of the Market, 2018 Q3* (Nov. 8, 2018), at 606, Table 12-15, "Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): September 30, 2018"., *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm-sec12.pdf.

[20] The forecast peak load for the 2021/22 delivery year was 152,667 MW, so 8.5 percent of this amounts to 12,976.7 MW. *See e.g.*, PJM Interconnection, 2021/2022 RPM Base Residual Auction Planning Period Parameters, at 1,

Q. **Please describe the second study PJM referenced in support of the 10-hour duration requirement for non-hydro ESRs.**

A. PJM noted in its compliance filing that a more recent study about Limited Energy Capability Resources (LECR) – referred to herein as the "2018 LECR Study" – also supports its 10-hour duration requirement for non-hydro ESRs.[21] PJM did not provide the 2018 LECR Study but noted that its publication is forthcoming in connection with an IEEE conference in February 2019. PJM did not include the 2018 LECR Study in its filing or provide a reference where the study could be accessed and reviewed, but stated that the study "concluded that ten hours of continuous output remains appropriate" to determine the capacity value of non-hydro ESRs.[22] I was not able to locate a copy of this study but I found a presentation by PJM staff entitled "Limited Energy Capability Resource Duration Requirement for the Capacity Market" that described the 2018 LECR Study. PJM staff gave this presentation at a September 14, 2018 PJM Market Implementation Committee meeting related to PJM's Order No. 841 Compliance ("September 2018 LECR Presentation").[23] I have included a copy of the September 2018 LECR Presentation as Exhibit 2.

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available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-uction-info/2021-2022/2021-2022-rpm-bra-planning-parameters-report.ashx?la=en

[21] PJM Transmittal at note 51.

[22] PJM Transmittal at note 51.

[23] PJM Interconnection, Limited Energy Capability Resource (LECR) Duration Requirement for the Capacity Market, Sept. 14, 2018, *available at* https://www.pjm.com/-/media/committees-groups/committees/mic/20180914-special/20180914-item-05-esr-duration-slidedeck-0914.ashx ("September 2018 Presentation"). PJM staff notes that the presentation is based on a paper submitted to IEEE for review and referenced the same 2019 IEEE technical conference that PJM referenced in note 51 of its Transmittal.

Q: Does the September 2018 LECR Presentation about the 2018 LECR Study support PJM's 10-hour duration requirement?

A: No. Based on my review of the September 2018 LECR Presentation about the 2018 LECR Study, which was the only publicly available information I was able to find about the study, the study does not explicitly examine the reliability implications of various duration requirements for ESRs. Because PJM has not provided a copy of the full 2018 LECR Study, neither PJM stakeholders nor the Commission can properly assess this study. Nonetheless, I have attempted to do so based on the information provided in the September 2018 LECR Presentation. According to the September 2018 LECR Presentation, the 2018 LECR Study assumes as a starting point that LECRs, which presumably include non-hydro ESRs, will serve 8.5 percent of peak load.[24] As noted above, this is significantly above PJM's current non-hydro ESR penetration level. Based on the September 2018 LECR Presentation, the 2018 LECR Study did not directly estimate the reliability implications of different duration requirements or penetration levels of non-hydro ESRs, such as the probability of falling short of the PJM resource adequacy requirement, as the 2010 Demand Response Study did. According to the September 2018 LECR Presentation, the 2018 LECR Study examined LECR penetration levels ranging from 1 to 20 percent of peak load and examined how the assumed charge and discharge patterns of LECR storage resources would

[24] September 2018 LECR Presentation at 5.

change the peak load profile.[25] For reference, the study states that an 8.5 percent penetration level, measured as a percentage of peak load, amounted to 12,470 MW of installed LECR capacity.[26] This level is significantly above the current 700 MW of installed battery storage in PJM and the 817.2 MW in the interconnection queue.[27] The September 2018 LECR Presentation also discussed the concept of "equivalent duration," defined as the amount of energy (in MWh) generated during the peak period divided by the maximum output (in MW) an LECR is assumed to generate based on the assumed penetration level and charge and discharge patterns in the 2018 LECR Study.[28] The equivalent duration figure discussed in the September 2018 LECR Presentation is not the same as PJM's continuous duration requirement. The continuous duration requirement refers to a resource's ability to generate a certain minimum level of output for a certain period of time. By contrast, the concept of equivalent duration in the September 2018 LECR Presentation measures the duration of time over which an LECR is assumed to generate electricity during the peak period based on the assumed load profile, LECR penetration level, and LECR charge and discharge patterns. As shown in Figure 1, an expert from the September 2018 LECR Presentation, the concept of equivalent duration explicitly assumes that an LECR's output will vary over the peak period, essentially following load.

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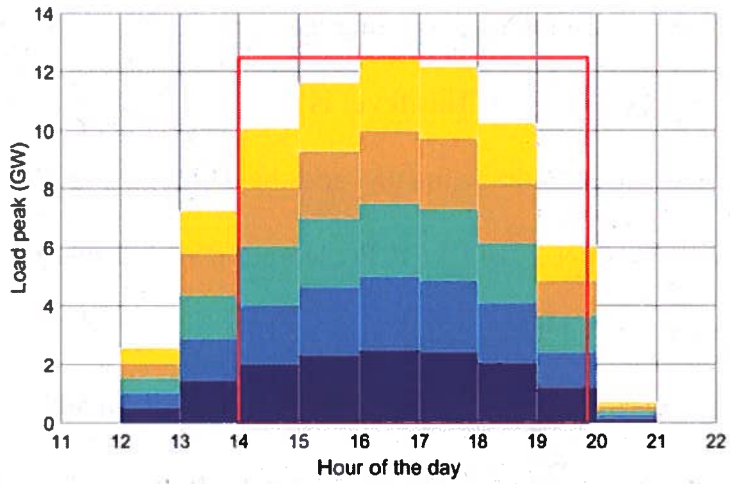
[25] September 2018 Presentation at 9.
[26] September 2018 Presentation at 5.
[27] See *supra* p. 10.
[28] September 2018 Presentation at 6.

__Figure 1: PJM Presentation on LECR Study – The Method of Equivalent Duration__



Source: PJM Interconnection, Limited Energy Capability Resource (LECR) Duration Requirement for the Capacity Market, September 14, 2018, at 6.

Q: What did the September 2018 LECR Presentation conclude?

A: The September 2018 LECR Presentation provides three conclusions which presumably reflect the conclusions in the 2018 LECR Study. The first conclusion is that LECRs in the RPM should meet a 10 hour *equivalent duration requirement*. Recall that the concept of equivalent duration, where resource generation output can vary over time, differs from PJM's continuous duration requirement. The second conclusion is that a 10-hour equivalent duration requirement would allow the PJM system to accommodate an LECR penetration of up to 20 percent. The third conclusion is that a 4-hour equivalent duration requirement would only allow the PJM system to accommodate an LECR penetration of less than 5 percent.[29] As such, the conclusions of the September 2018 LECR Presentation do not appear to

[29] September 2018 LECR Presentation at 13.

relate to the continuous duration requirement. Given the difference between a *continuous duration requirement* and the concept of *equivalent duration* discussed in the September 2018 LECR Presentation, and assuming that PJM's September 2018 LECR Presentation accurately summarizes the 2018 LECR Study, the study does not appear to support PJM's 10-hour continuous duration requirement.

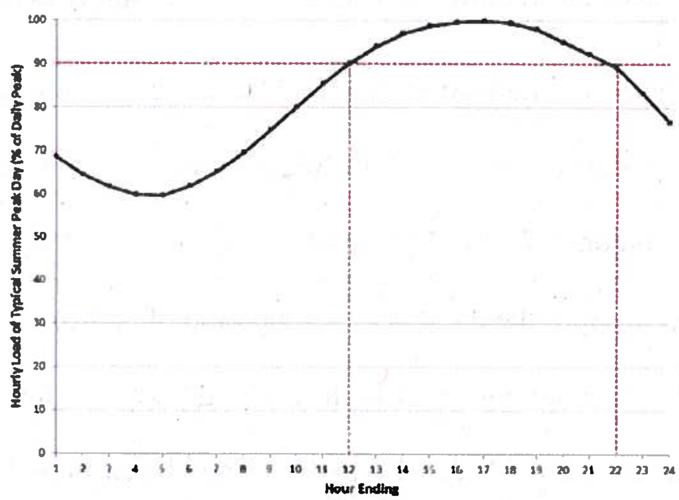
Q: Did PJM raise other arguments related to the ten-hour continuous duration requirement?

A: Yes. Jeffery Bastian, Manager, Capacity Market Operations, stated that a 10-hour continuous duration requirement for ESRs is "consistent with the period of elevated demand on a typical day".[30] Mr. Bastian also noted that PJM loads are at or above 90 percent of the daily peak for a period of approximately 10 hours. However, this fact does not speak to the reliability implications of the continuous duration requirement that PJM uses to determine the capacity value of various resources, such as non-hydro ESRs, to meet the reliability requirement. In fact, the load profile shown in Figure 1 of Mr. Bastian's affidavit (shown in Figure 2 below) demonstrates that the peak load in PJM is not sustained for continuous 10-hour period, but instead follows a well-known diurnal pattern. And as Mr. Bastian states, there are periods of time during the 10 hours that surround the peak load hour where system load ranges from 90 percent to 100 percent of peak load.[31] This load pattern suggests that PJM has some flexibility to both meet its required

[30] Affidavit of Jeffery D. Bastian, Docket No. ER19-469-000 (December 3, 2018), at 3. ("Bastian Affidavit").
[31] Bastian Affidavit at 3.

reserve requirement and can use a continuous duration requirement of less than ten hours to determine the capability of certain capacity resources. As I discuss further below, PJM has already availed itself of this opportunity for intermittent resources.

Figure 2 – PJM Summer Weekday Load Shape



Affidavit of Jeffery D. Bastian, Docket No. ER19-469-000 (December 3, 2018), at 4

Q: Does PJM have the flexibility to determine different capacity qualification requirements for different capacity resource types?

A: Yes. Schedule 9 of the Reliability Assurance Agreement explicitly states that PJM should take into account the different characteristics of various resource types when determining their capacity qualification requirements. Specifically, Schedule 9 states that "the rules and procedures [to determine and demonstrate the capability of a generation resource] shall recognize the difference in types of generating units and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, and system operating policies."[32]

Q: What other evidence or arguments did Mr. Bastian present to support the ten-hour continuous duration requirement?

A: Mr. Bastian stated that the 2010 Demand Response Study "reaffirmed the significance" of the ten-hour minimum period to effectively manage loads during peak conditions."[33] However, as I explained previously, the 2010 Demand Response Study does not support a 10-hour duration requirement for non-hydro ESRs because the study analyzed a different resource type (*i.e.*, Limited Demand Response Resources), is based on out-of-date inputs, and an assumed penetration level (8.5 percent) that far exceeds what can be reasonably expected of non-hydro ESRs in the near term.[34] Mr. Bastian and PJM in its Transmittal also argue that the method for determining the capability of pumped storage hydro resources should be applied non-hydro ESRs because non-hydro ESRs are dispatchable. Mr. Bastian and PJM argue that the four-hour continuous duration requirement PJM currently uses to determine the capability value of intermittent capacity resources should not apply to non-hydro ESRs because unlike intermittent resources, non-hydro ESRs are dispatchable.[35]

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[32] PJM Reliability Assurance Agreement, Schedule 9.
[33] Bastian Affidavit. at 4.
[34] See *supra* p. 10.
[35] See Bastian Affidavit. at 6-9 and PJM Transmittal at 26-27. PJM and Mr. Bastian raise a similar argument for Energy Efficiency capacity resources.

Q: Does distinguishing non-hydro ESRs from intermittent resources support applying a 10-hour continuous duration requirement to non-hydro ESRs?

A: No. Simply stating a well-known operational difference between intermittent resources and non-hydro ESRs does not amount to supporting the 10-hour duration requirement for non-hydro ESRs. While it is true that non-hydro ESRs are dispatchable and have different operational characteristics than intermittent resources, it is equally true that non-hydro ESRs differ from pumped storage hydro resources and other dispatchable resources, such as combined cycle natural gas resources. PJM argues that non-hydro ESRs should not be subject to the same capacity qualification procedures as intermittent resources because ESRs have different operating characteristics to intermittent resources. The same rationale can be used to argue that non-hydro ESRs should not be subject to the same capacity qualification procedures as pumped storage hydro resources. Pumped-storage hydro resources are fundamentally different than non-hydro ESRs. For example, pumped-storage hydro resources face operational constraints based on the amount of water in their reservoir storage, which can also be limited by environmental or other regulatory restrictions. Non-hydro ESRs are not subject to such constraints. Additionally, due to their different generation technologies, non-hydro ESRs are also able to respond quickly to dispatch, while some pumped storage resources are slow to respond to dispatch instructions.[36] Although the PJM Reliability Assurance Agreement gives PJM the ability to consider the

[36] PJM Transmittal at 16.

unique operational characteristics of a given class of resources when PJM determines the capacity qualification procedures for that resource class, PJM has not chosen to do so for non-hydro ESRs and instead assumed that non-hydro ESRs should be subject to the same capacity qualification procedures as pumped storage hydro resources despite the significant differences between the two classes of resources.

Q: **Provided it doesn't impair reliability, what are the benefits using different methods to determine the capability of different types of capacity resources?**

A: Provided the same level of reliability is procured and reliability is not impaired, the benefit of using different methods to determine the capacity value of different resource types is that doing so allows PJM and PJM loads to extract the most value from the set of installed resources that are capable of providing a portion of the PJM capacity requirement. As noted above, the PJM Reliability Assurance Agreement seemingly recognizes this benefit and affords PJM the latitude to extract this benefit on behalf of load.

Q: **What are the consequences of having a continuous duration requirement that is higher than necessary to maintain reliability?**

A: A continuous duration requirement that is more stringent than necessary could raise costs to load by unnecessarily preventing resources that are technically capable of offering and providing capacity in a manner that does not impair reliability from offering their supply into the RPM. As a general matter, limiting the quantity of supply that can offer a market can result in a higher clearing price, which in this case could lead to higher capacity costs for PJM loads. Furthermore, a significant proportion of non-hydro ESR will likely be located with other intermittent resources, such as wind and solar. As such, an overly-restrictive method of determining the capacity value of a non-hydro ESR could have the unintended consequence of significantly reducing the aggregate capacity values of such hybrid facilities. As such, it's critical that PJM carefully study the method it uses to determine the capacity value of non-hydro ESRs.

Q: What continuous duration requirement do other RTOs/ISOs currently use for non-hydro ESR?

A: While the capacity qualification procedures for non-hydro ESRs in other regional transmission organizations (RTOs) and independent system operators (ISOs) are not necessarily directly applicable to PJM, such procedures are nonetheless informative because other RTOs/ISOs that operate centralized capacity markets have the same general objective as PJM, namely establishing a method to determine the capacity value of non-hydro ESRs to provide capacity in a manner that contributes to the reliability requirement. Based on their respective minimum duration requirements for non-hydro ESRs, other RTOs/ISOs with centralized capacity markets have determined that non-hydro ESRs can reliably provide a quantity of capacity equal to the level they can generate during a continuous period of either two or four hours. Specifically, the Midcontinent Independent System Operator, Inc.[37] and the New York Independent System Operator, Inc.[38]

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[37] Midcontinent Independent System Operator Inc., Docket No. ER19-465-000, Prepared Direct Testimony of Kevin A. Vannoy, at 15.

[38] New York Independent System Operator Inc., Docket No. ER19-467-000, Transmittal at 6. NYISO is considering whether to increase this requirement.

have a 4-hour continuous duration requirement non-hydro ESRs and ISO New England Inc.[39] has a two-hour continuous duration requirement for non-hydro ESRs. The fact that PJM's 10-hour continuous duration requirement far exceeds the requirements of other RTOs/ISOs does not by itself demonstrate that PJM's continuous duration requirement is too stringent. However, this significant difference in capacity qualification procedures suggests that PJM should study whether a 10-hour continuous duration requirement for non-hydro ESRs is needed to maintain reliability given the non-hydro ESR penetration levels expected over the next few years. PJM should also consider the fact that non-hydro ESRs, like all resources, will also be subject to the exact same performance requirements as all capacity resources, and will be subject to penalties if they do not perform when called upon.[40] The existence of these penalties will give non-hydro ESRs, and indeed all resources, an additional incentive to perform in peak periods when the likelihood of incurring penalties for non-performance tends to be greatest.

This concludes my affidavit.

[39] ISO New England, Inc., Docket No. ER19-470-000, Transmittal at 15.
[40] PJM Transmittal at 29.

AFFIDAVIT OF EMMA NICHOLSON

Emma Nicholson, being duly sworn, deposes and states that she prepared the Affidavit of Emma Nicholson, and the statements contained therein are true and accurate to the best of her knowledge and belief.

Emma Nicholson

SUBSCRIBED AND SWORN BEFORE ME, this 7 day of February, 2019.

Notary Public

JENNIFER L. HARWELL
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires January 31, 2022

JENNIFER L. HARWELL NOTARY PUBLIC DISTRICT OF COLUMBIA EXP. 1-31-22

My Commission Expires: January 31, 2022

Exhibit 1

Thomas A. Falin Affidavit and 2010 Demand Response Study

Attachment A

Affidavit of
Thomas A. Falin
On Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, LLC) Docket No. ER11-____-000

AFFIDAVIT OF THOMAS A. FALIN
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Thomas A. Falin. My business address is 955 Jefferson Avenue, Norristown, PA 19403. I currently serve as the Manager of the Resource Adequacy Planning Department for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its filing in this proceeding to modify its rules concerning the commitment of load management capabilities to help meet the PJM region's capacity needs.

2. I have served in my current position since October, 2002. The Resource Adequacy Planning Department at PJM is responsible for assessing the long term resource adequacy of the PJM system by conducting reserve margin studies, evaluating generator performance and developing long-term load forecasts. Among other duties, the Resource Adequacy Planning Department is responsible for developing many of the key reliability metrics that are incorporated each year in PJM's Reliability Pricing Model ("RPM"), including the installed reserve margin, peak load forecasts, Capacity Emergency Transfer Objectives ("CETO"), and equivalent demand forced outage rates for PJM generation facilities. In my capacity as Manager of that department, I oversee the development of these analyses every year. Prior to assuming my current position, I served as a senior engineer in the Capacity Adequacy Planning Department for three years, performing resource adequacy studies and serving as chair of several planning-related PJM stakeholder groups.

3. Prior to joining PJM, I worked for fourteen years in the System Planning Department at PECO Energy Company performing transmission and distribution studies and representing PECO on various PJM committees and working groups. I hold a Bachelor of Science Degree in Mechanical Engineering from Princeton University and a Master of Science Degree in Systems Engineering from the University of Pennsylvania. I am an active participant on several industry groups concerned with resource adequacy and reliability, including the NERC Resource Issues Subcommittee and the Reliability First Corporation Resource Adequacy Subcommittee.

4. PJM for many years has allowed load-serving entities and curtailment service providers to commit in advance that they will reduce loads to a certain level or by a certain amount when called upon by PJM during, or in anticipation of, emergency conditions. Under RPM, PJM's current approach to assuring resource adequacy, these commitments are known as Demand Resources. As currently defined in the tariff, Demand Resource commitments have important limitations. Specifically, the interruption commitments are limited to the hours from 12:00 p.m. Eastern Prevailing Time ("EPT") to 8:00 p.m. EPT on non-holiday weekdays in the

months of June through September; a maximum of six consecutive hours per call for interruption; and a maximum of ten calls for interruption per summer. Given concerns that these limitations on Demand Resource commitments have become outmoded with the significant growth, under RPM, in the Demand Resources on which PJM depends for reliability, PJM has filed in this proceeding to add a less limited summer-only load management product (known as Extended Summer Demand Resources or "Extended Summer DR") and a year-round product (known as Annual Demand Resources, or "Annual DR"). PJM is retaining its current Demand Resource product, but renaming it Limited Demand Resources or Limited DR. In my affidavit, I will support these market rule changes by: 1) describing PJM's analyses of the reliability impacts of increased reliance on the current limited Demand Resource product; and 2) showing, and providing an example of, the procedures and calculations PJM will use to set targets each year for the maximum quantities of Limited DR and Extended Summer DR that are compatible with reliability.

5. The Demand Resource limitations described above were first established by PJM's predecessor power pool in 1991 as a means for the participating public utilities to receive a credit (known as the Active Load Management, or ALM, Credit) against the installed capacity they otherwise were required to commit to assure reliable service to their loads. Those limits were based on an analysis of the peak periods during the year when PJM would be most at risk of shedding load in the Mid-Atlantic Area Council ("MAAC") region then served by PJM. Those limits on when, how often, and for how long, PJM could call on ALM also were based on an assumption that ALM commitments would comprise a very small share of the total capacity committed to PJM. Specifically, capacity planning analyses performed when ALM was first established in 1991 assumed that it would comprise no more than five percent of PJM's forecast unrestricted peak load. By "unrestricted" peak load, I mean the load that would be expected if load management is not implemented. In 1995, PJM updated its planning analysis and determined that reliability concerns would arise if ALM exceeded 7.5 percent of forecast unrestricted load.

6. Given the rapid increase in Demand Resources offered and cleared in the RPM auctions, PJM management asked the Resource Adequacy Planning Department to conduct an updated analysis of the maximum levels of Demand Resources on which PJM could reliably depend. That analysis, prepared under my direction and supervision, was completed in May 2010 ("May, 2010 Analysis"). A copy of that analysis is provided as Exhibit 1 to this affidavit. The May, 2010 Analysis investigated two distinct questions about the reliability implications of the current limits on Demand Resources: i) at what level of Demand Resource commitment is there an unacceptable risk that PJM will have to call on Demand Resources more than ten times in a season; and ii) assuming Demand Resources commit at the level determined in response to the first question, for how many hours must Demand Resources interrupt their loads when called upon on a given day to provide adequate assurance that Demand Resources will be effective in reducing the peak during all relevant times of the day?

7. As detailed in Exhibit 1, PJM concluded in response to the first question that, using data from the 2013-14 Delivery Year, PJM can be 90 percent confident that it would not need to call on limited resources more than ten times in one summer so long as the committed Demand Resources equated to no more than 8.5 percent of the peak load (assuming the auction

procures capacity at a level equal to the installed reserve margin). As to the second question, PJM concluded that the current six-hour interruption limit poses an unacceptable risk that deployment of Demand Resources would not reduce the peak load for a given day, but would instead merely shift that peak to a time outside the six-hour window, when Demand Resources cannot be called. Shifting the daily peak to an hour outside the six-hour interruption window would result in a peak load that is inconsistent with the peak load used in PJM's planning studies, which assume that the unrestricted PJM peak is reduced by the full amount of dispatched Demand Resources. If Demand Resource penetration is high enough, the daily peak could shift to an earlier or later hour and PJM planning studies would be understating the actual load on a peak day. This understatement of peak loads could conceal reliability violations and therefore result in an unreliable system. Our analysis showed that increasing the interruption window from six hours to ten hours would avoid the risk of shifting, rather than reducing, the peak load. The May, 2010 Analysis therefore proposed to require Demand Resources to interrupt their loads for up to ten hours at a time.

8. Informed by its stakeholder process however, PJM determined to retain the existing Demand Resource product, including its six-hour interruption window. PJM's Resource Adequacy Planning staff therefore conducted additional analysis to determine the level of reliance on limited resources that would not present unacceptable reliability risks, given that the limited product need only respond for a maximum of six hours. The calculation procedure PJM developed to address this question is shown in Exhibit 2 to my affidavit, and an example applying that calculation to PJM's 2013-14 Delivery Year is shown in Exhibit 3. That analysis concludes that PJM can be reasonably confident that it would not need to call on time-limited resources outside their six-hour window so long as the committed Demand Resources equate to no more than 4.7 percent of the peak load (again, assuming the auction clears at the IRM).

9. Since the ten-call and six-hour limits both apply to Demand Resources as currently defined, the reliability implications of Limited DR are defined by the more restrictive of these two limitations. Therefore, applying the analyses for both Demand Resource limitations (i..e, calling no more than ten times per summer, and for no more than six hours at a time) to the 2013-14 Delivery Year indicates that PJM should commit limited resources (assuming the auction clears at PJM's Installed Reserve Margin) at no more than 4.7 percent of its peak load forecast.

10. PJM's analyses described above reasonably rely on models, assumptions and techniques that PJM also regularly uses for its transmission expansion and capacity planning efforts. The probabilistic peak load model used in the analyses is also used by PJM for long-term load forecasting to ensure the transmission and resource adequacy of the region. The probabilistic capacity model used in the Demand Resource analyses is based on an approach that is widely used in the industry to perform Loss of Load Expectation ("LOLE") studies. PJM has been using this capacity model for over thirty years to assess resource adequacy and to establish the installed reserve margin required to satisfy the "one day in ten years" LOLE standard. The PJM Planning Committee reviewed the May, 2010 Analysis and found its approach, assumptions, and conclusions reasonable.

11. Assuming acceptance of the tariff changes in this filing, PJM will calculate reliability targets each year for the Limited DR and Extended Summer DR products, for both the PJM Region as a whole and for any Locational Deliverability Area ("LDA") that typically binds in the RPM auction and/or has experienced a significant increase in reliance on Demand Resources for capacity. Those LDAs currently are the MAAC, Eastern MAAC and Southwestern MAAC LDAs. PJM will monitor Demand Resource participation levels for all LDAs each year and review the results of those analyses with stakeholders.

12. PJM's current draft calculation procedures for these targets are shown in Exhibit 2. PJM plans to review these procedures with stakeholders and incorporate them in the appropriate PJM manual. The procedures will be applied in January 2011 to data for the 2014-15 Delivery Year so that the targets can be posted on February 1, 2011 along with the other auction parameters for the May 2011 Base Residual Auction for that Delivery Year. Conceptually, these targets are very much like the "minimum internal resources required" calculations that PJM presently calculates to define locational capacity constraints.

13. The Limited Demand Resource Reliability Target is the maximum amount of Limited Demand Resources that can be reliably procured in an auction, assuming PJM procures resources in the auction equal to the level of its Reliability Requirement (as defined in the PJM tariff). The target will be expressed as a percentage of forecast peak load, and converted to an "unforced" basis so that it can be correctly deducted from the Reliability Requirement (which is on an unforced basis). Generally, the calculation method tracks the analyses described above for assessment of the reliability impacts of the frequency and duration limitations of the existing Demand Resource product. PJM will determine the level of limited resources (as a percentage of peak load) at which there is an unacceptable (i.e., ten percent) probability that PJM will have to call limited resources more than ten times in a summer. PJM then will determine the level of limited resources at which it can be reasonably confident that it would not need to call on those resources outside their six-hour window. PJM will set the Limited Demand Resource Reliability Target at the more restrictive result from these two analyses.

14. Similar to the Limited DR Reliability Target, PJM will determine the Extended Summer DR Reliability Target each year in accordance with the attached procedure. As detailed on Exhibit 2, PJM will develop hundreds of daily load forecasts (varying based on differing assumptions on weather patterns) and corresponding daily forecasts of the expected available generation capacity resources, for each of the approximately 260 weekdays in a Delivery Year. PJM will then establish a base case that fixes the installed reserve margin at the PJM Board-approved installed reserve margin**.** PJM will model Extended Summer DR in the base case as a resource that is 100% available from May 1 through October 31 and unavailable from November 1 through April 30. PJM will then vary the level of Extended Summer DR committed, and correspondingly reduce the level of annual resources committed, and calculate the impact on system LOLE. In consultation with stakeholders, and consistent with the common use of a 10 percent statistical confidence level in probabilistic models, PJM is using a 10 percent increase in system LOLE from inclusion of Extended Summer DR in this calculation procedure as an acceptable level of risk.

15. As shown on Exhibit 3, the Resource Adequacy Planning Staff has applied this calculation procedure to data for the 2013-14 Delivery Year. That calculation indicates that Extended Summer DR (together with Limited DR) can comprise 10.6 percent of PJM's peak load (again, assuming the auction clears at the IRM) without increasing the PJM system risk of a loss of load event by more than 10 percent. Note that although this target combines Extended Summer DR and Limited DR, PJM will have a separate target (as a subset of that larger target) for the maximum level of Limited DR, which, as I illustrated above, would have been 4.7 percent for 2013-14.

16. Exhibit 2 also shows the procedures PJM will use to calculate these two reliability targets for each of the three relevant LDAs, and Attachment C illustrates application of those rules to planning data for the 2013-14 Delivery Year. The LDA procedure used to establish the Limited DR Reliability Target based on the six hour interruption limitation is identical to that used for the RTO. The LDA procedure used to establish the Extended Summer DR Reliability Target is identical to that used for the RTO with one exception. Rather than being modeled at the Board-approved installed reserve margin, each LDA is modeled at a reserve margin based on the sum of the generation internal to that LDA and the LDA's Capacity Emergency Transfer Limit. This change is necessary because the IRM is applicable to the PJM Region as a whole and not to any individual LDA. The sum of an LDA's internal generation and its CETL represents the maximum amount of resources that will be available to serve load within that LDA. As shown on Exhibit 3, the Limited Demand Resource Reliability Targets for the MAAC, Eastern MAAC, and Southwestern MAAC LDAs for 2013-14 would have been 5.5%, 6.3%, and 6.2%, respectively; and the Extended Summer DR Reliability Targets for those three LDAs would have been 11.1%, 14.2%, and 13.7%, respectively.

17. This concludes my affidavit.

Th A. Fal

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER11-___-000

Thomas A. Falin, being first duly sworn, deposes and states that he is the Thomas A. Falin referred to in the document entitled "Affidavit of Thomas A. Falin," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief in this proceeding.

Thomas A. Falin

Subscribed and sworn to before me, the undersigned notary public, this 2nd day of December, 2010.

Dianne Maguire

Notary Public

My Commission expires: 12/18/2012

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Dianne Maguire, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Dec. 18, 2012
Member, Pennsylvania Association of Notaries

Exhibit 1

May, 2010 Analysis

DEMAND RESOURCE
SATURATION ANALYSIS

Resource Adequacy Planning Department

May 2010

I PURPOSE

The purpose of this study is to evaluate the reliability value of Demand Resources (DR) in the PJM Region. Initiation of the study was prompted by the recent increases in the amount of DR committed in PJM, coupled with the limited interruption requirements for DR. This study determines the amount of DR at which its reliability value saturates under the current requirements regarding the number and duration of interruptions.

II BACKGROUND

PJM's first demand side management program, known as Active Load Management (ALM), was implemented in 1991. Its purpose was to allow LSEs to reduce their capacity obligations by registering interruptible load customers that would contractually commit to interrupt their load during peak demand periods. The call for the interruption was at the command of PJM Operations and verification and compliance reviews were performed at the end of each summer.

The conceptual basis for ALM was that the customers' commitment to interrupt during peak demand periods eliminated the need for those customers to procure generation capacity for the interruptible portion of their load. PJM stakeholders recognized that this premise was valid only if ALM customers (that committed no capacity to PJM) were interruptible over all loss of load risk periods so that their demand did not contribute to PJM's loss of load probability (LOLP). To ensure this assumption was valid, PJM examined load duration curves for the then MAAC region. The result of this analysis was to establish the following requirements for qualifying an interruptible load program as ALM:

- Customers must be interruptible for up to ten times per summer
- Each interruption could be for up to six hours over the 1200-2000 time period of all summer weekdays
- The amount of ALM was limited to 5% of the forecasted unrestricted peak load for each zone

Based on updated analysis performed in 1995, the limit on ALM was raised to 7.5% of the RTO forecasted unrestricted peak load. Since 1995, the 7.5% limit and the requirement for ten interruptions per summer have been verified annually in the Installed Reserve Margin (IRM) Study. The actual amount of ALM in PJM has varied from about 1% to 4% over the 1991–2006 period and the ALM/DR limit has remained at 7.5%.

The amount of Demand Resources (including both DR and Interruptible Load for Reliability) has increased dramatically in recent years. The amount of DR in PJM was 1,677 MW in 2006/2007 and is projected to be over 8,500 MW in 2010/2011 (a fivefold increase). The corresponding increase in DR as a percent of load has been from 1.2% in 2006/2007 to 6.3% in 2010/2011. As the actual amount of DR in PJM approaches the limit of 7.5%, it is necessary to re-examine the determination of the limit and the DR interruption requirements that impact it.

III RTO ANALYSIS

PJM has more sophisticated analytical tools now than were available in 1995 when the issue of DR saturation was last investigated. Specifically, PJM now has a load forecasting tool that can produce a distribution of expected daily peaks. Because DR is implemented on a daily basis, this improved analytical capability allows for a more robust examination of the probability of implementing DR a given number of times over the summer period.

This study assesses the reliability value of DR given its two interruption requirements (ten interruptions per year and a six hour duration per interruption). Each of these requirements was investigated separately and the methodology and results are described below.

Ten Interruption Requirement

The general approach was to convolve the daily peak load distributions from the top 20 summer load days with the available capacity distribution to determine the frequency with which reserves would drop below a given threshold that would, in turn, trigger implementation of DR. This required development of a load and a capacity model.

Load Model:

1. The 2013 summer forecast distributions are obtained for the 20 CP (coincident peak) days from the 2009 load forecast. There are 481 scenarios, each representing a particular weather pattern (13 scenarios from each of 37 historical weather years). For a given weather scenario, the CP1 day represents the highest load forecasted for the summer of the forecast year. The CP2 day represents the 2^{nd} highest load forecasted, etc.

   Note: At the time the 2009 forecast was developed, ATSI was not included.

2. The median load value from the CP1 day corresponds to the 50/50 forecasted peak for the RTO in 2013/14. The 20 CP distributions are per-unitized on the

median of the CP1 day peak. In other words, the ratio of each of 481 x 20 loads to the median forecast peak is calculated. Using the ratio calculated, the 481 x 20 loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows the 20 CP day distributions to be shifted up or down by altering the seasonal peak load.

<u>Capacity Model:</u>

3. The PJMRTO cumulative capacity probability table from the 2009 IRM Study is used. The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance or planned outage. The capacity distribution from week 10 (the peak week in the 2009 IRM Study for DY 2013/2014) is assumed to be constant for the entire period of 20 CP days. This assumption is made because there are no planned or maintenance outages over the summer period and the generator EFORd's are modeled as constant across the Delivery Year.

4. DR is assumed to be a 100% available resource that is available to assist the system whenever PJM operating reserves fall below a certain margin. The operating reserve is thus the margin between load and available capacity at which DR is expected to be invoked. An operating reserve margin of 1,300 MW is assumed for the RTO. This value is documented on page 11 of PJM Manual 13 and represents the RTO's synchronized/spinning reserve requirement that is based on the loss of the largest PJM generating unit.

<u>Analysis:</u>

5. Using the normalized distributions from Step 2, and the cumulative capacity probability table from Step 3, the LOLE is calculated for each of the 481 x 20 loads and aggregated. The peak load is iteratively increased until the Installed Reserve Margin (with no DR assumed) of 15.3% is established. 15.3% is the approved IRM for the 2013/2014 DY and is used by RPM to procure capacity resources for the RTO. This solved case forms the base case. Note: LOLE is always calculated at zero margin, i.e. load exceeds available capacity (including DR).

6. The 20 CP days from each of the 481 scenarios are derived from various weather patterns that simulate the need for invoking DR. At the assumed operating reserve margin, the following occur:

    a. If the margin between load and an available capacity state is greater than the operating reserve, no Loss of Load (LOL) occurs and no DR is invoked.

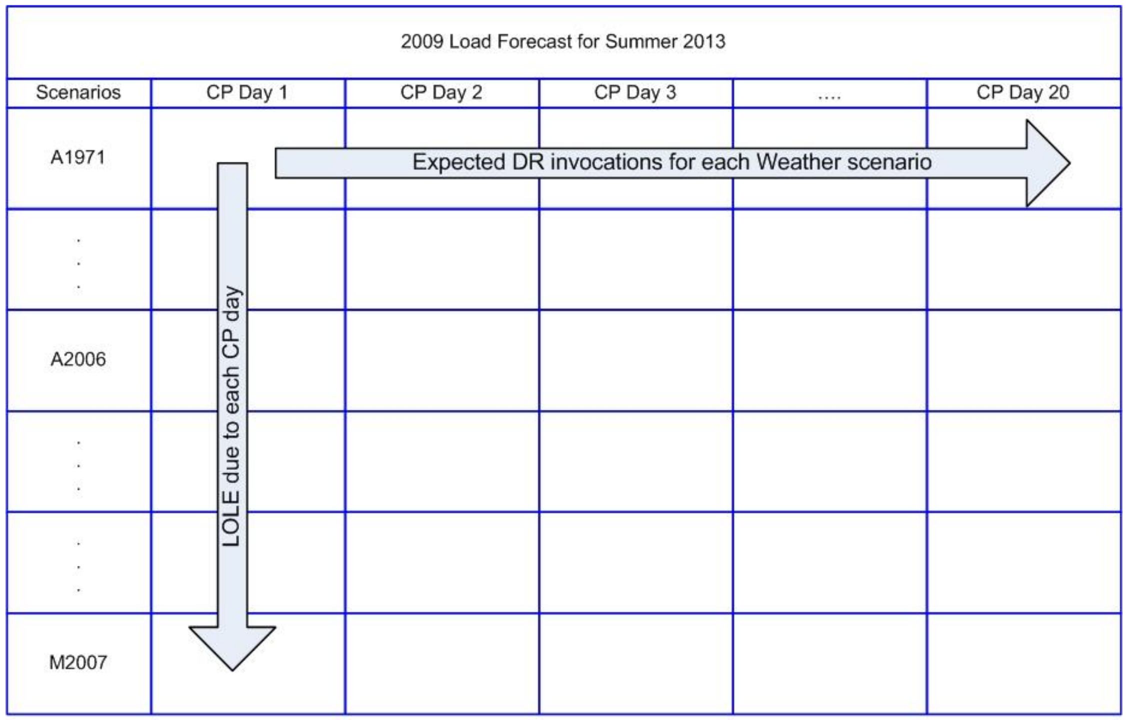
    b. If the margin between load and an available capacity state is less than the operating reserve, DR is invoked if available. No LOL occurs until the margin becomes less than or equal to zero. For each of the 20 CP days, the first instance (or capacity state) in which the margin falls below the operating reserve is used to determine the probability DR will be invoked on a particular day. For a CP day, DR can be invoked with a probability between zero and one depending on the capacity state at which the margin falls below operating reserve. For example, if (Capacity-load) <= operating reserves for all capacity states, the probability of DR invocation on that day is 1. Alternatively, if (Capacity-Load) > operating reserves for all the capacity states, the probability of DR invocation is zero. The probability of DR invocation is calculated for all 20 CP days in a weather scenario and is then summed. This sum represents the expected number of DR invocations in that scenario.

c. If, after invoking DR, the margin becomes less than zero for certain states, LOL occurs. The LOLE is aggregated for each CP day across all scenarios.

7. Using the 1,300 MW operating reserve margin, the amount of DR is progressively increased. The increase in DR is modeled as 100% available generation and the additional DR replaces an equal amount of generation resources so that the 15.3% reserve margin is held constant. Thus, as the amount of DR increases in the system, more generation is displaced and also the expected number of times DR is invoked increases.

8. A histogram of the expected DR invocations from the 481 scenarios is developed for each level of DR penetration. The histogram represents the frequency with which DR is implemented X number of times as X is varied from zero to 20.

Figure 1 below illustrates Step 5 - Step 8 for a given level of DR penetration.



- LOLE due to all 20 CP days is summed to calculate Total LOLE.
- Expected DR invocations for all 481 weather scenarios are used to create a Histogram

FIGURE 1

Results

The histogram described in Step 8 above can be aggregated into a cumulative probability curve that represents the likelihood that DR is implemented X or fewer times. That aggregation is depicted in Figure 2 below for ten or fewer interruptions:

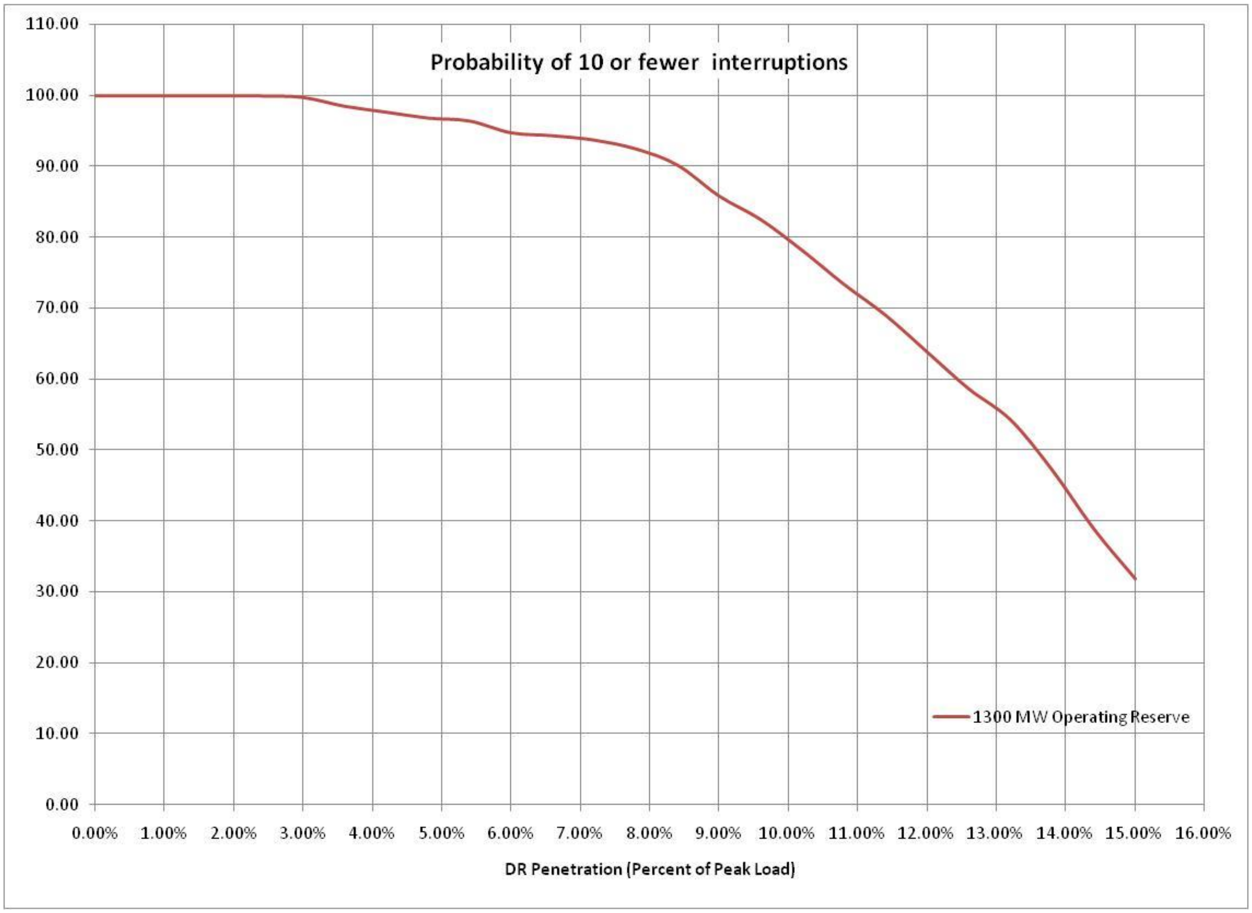


FIGURE 2

Figure 2 is based on a PJM case modeled at the 15.3% IRM reserve level and DR invocation is assumed whenever the operating reserve margin drops below 1,300 MW. Each DR invocation is counted as one event, regardless of the amount by which reserves drop below the 1,300 MW margin. This assumption is consistent with PJM operating practice and the practical reality of emergency conditions. PJM Operations calls for DR several hours in advance of the actual need when the peak load for that day is not known. Typically, PJM Operations does not have the need to call for the amount of DR that would restore reserves exactly to the 1,300 MW margin. Rather, on a typical PJM emergency day, all the DR in the affected area is invoked.

Figure 2 shows the likelihood that ten or fewer DR interruptions are needed as the amount of DR is increased across the horizontal axis. For instance, if DR were only 3% of the peak load, there is virtually a 100% chance that DR would be invoked 10 or fewer times (or a 0% chance it would need to be invoked more than 10 times). As the amount of DR increases, the probability of invoking DR ten or fewer times decreases (or, put another way, the probability of needing DR more than ten times increases).

Based on the information in Figure 2, engineering judgment must be applied to choose a DR penetration level at which PJM is comfortable that the probability of needing more than ten interruptions is not too large. A reasonable DR limit might be 8.5%, which is the point at which there is only a 10% chance that more than ten interruptions are needed (or, as indicated in Figure 2, a 90% chance of needing ten or fewer interruptions).

Sensitivity study results indicate that if the operating reserve margin were increased or decreased from the 1,300 MW level assumed in the base case, the DR saturation point would shift by a roughly equal MW amount in the opposite direction. For example, if the operating reserve margin at which DR is implemented were decreased to 1,000 MW, the DR saturation point would increase by approximately 300 MW.

Figure 2 is based on the current PJM requirement of ten interruptions. Figure 3 below illustrates the same case under the assumption of five or fewer and 15 or fewer interruptions.

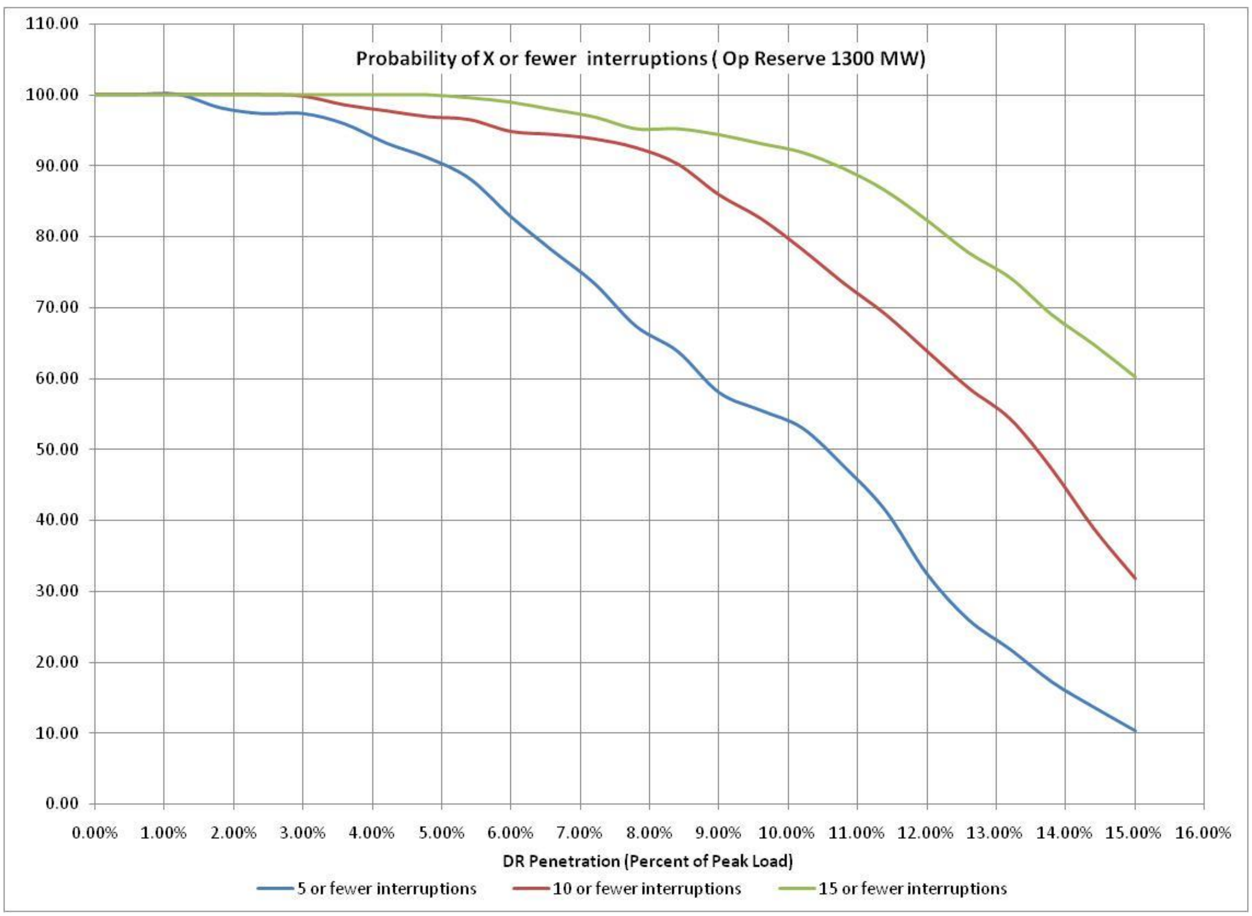


FIGURE 3

The red curve in Figure 3 is the same as the curve in Figure 2. (Both are based on ten or fewer interruptions.) The green curve in Figure 3 shows the probability of invoking DR 15 or fewer times as the amount of DR is increased across the horizontal axis. So, for example, if the 90% threshold were applied, DR could be about 11% of the forecasted unrestricted load. 11% DR would be the level at which there is only a 10% chance of requiring more than 15 interruptions. Figure 3 therefore illustrates that, if the interruption requirement were increased from 10 interruptions to 15, the limit on DR could be increased from 8.5% to 11% based on the same 90% confidence threshold.

Six Hour Duration Requirement

The second area of investigation concerns the six hour duration requirement currently applicable to DR. The intent of the DR program is to shave the daily peak load, not to shift the peak to an hour outside the six hour DR window. If the DR amount increases to a certain level, however, implementing DR could have the effect of shifting the daily peak to an early afternoon or evening hour. If this occurred, the daily peak would not be reduced by the full amount of DR. This concept is illustrated in Figure 4 below:

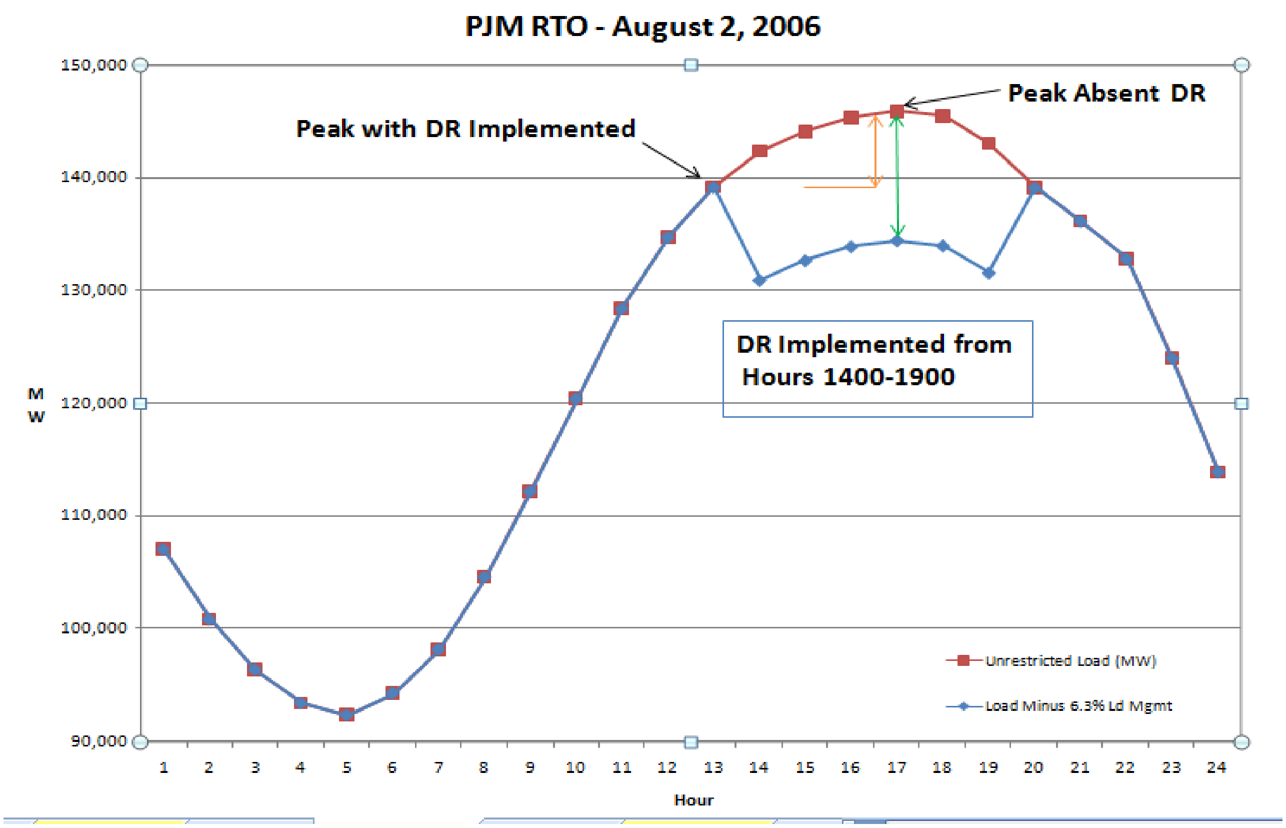


FIGURE 4

Figure 4 shows the hourly load curve from PJM's all-time peak day of August 2, 2006. The red curve shows the unrestricted load. If DR had been implemented over the highest six load hours of that day, the metered load would have followed the blue curve. (In this example, DR is assumed to be 6.3% of the weather-normalized peak. A 6.3% DR level is projected for the 2010/2011 Delivery Year.) As illustrated in the figure, the impact of implementing DR is to shift the daily peak to 1300 hours. As a result, the reduction in the daily peak (the vertical orange line) is less than the amount of DR implemented (the vertical green line).

To ensure the daily peak is reduced by the full amount of DR, the DR interruption window needs to be expanded to ensure that the peak of the day still falls within the DR interruption window. Figure 5 evaluates this issue for PJM's all-time peak day of August 2, 2006. The figure shows that the DR interruption window would need to be expanded to ten hours to ensure that the daily metered peak still falls within the DR window after DR is fully implemented. The assumed amount of DR for this analysis was 8.5% of the unrestricted load. The 8.5% level was selected based on results from the ten interruption investigation described in a previous section of this report.

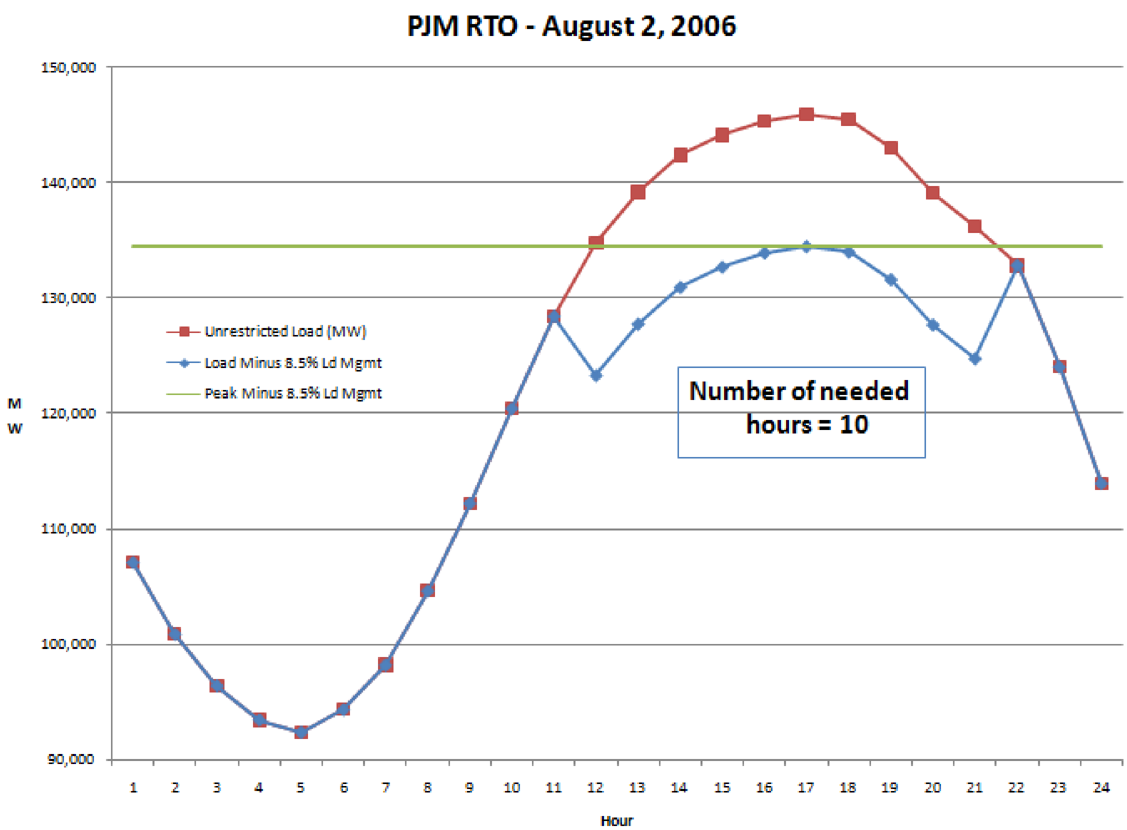


FIGURE 5

Figure 5 indicates that a ten hour DR interruption window is required for this particular day. The goal is to ensure that the green horizontal line is the metered peak. Therefore, any red data point falling above the green line would need to be reduced by implementing DR. There are ten red data points above the green line, so the interruption window, for this particular day, needs to be ten hours.

The required DR window can vary based on the particular load day being examined. This issue was investigated for each of the PJM annual peak load days from 2005-2009 and for any load day over that period on which the unrestricted peak was greater than the 50/50 weather-normalized peak load. These days would be most likely to require invocation of DR. In all these cases, the amount of DR was assumed to be 8.5% of the unrestricted peak load. For each day, the required DR interruption window was determined based on the same approach used in Figure 5. The results are summarized below in Table 1. (The load percentile column indicates where the load falls on the peak day (1CP) load distribution of that particular year.)

REQUIRED DR INTERRUPTION WINDOW FOR SELECTED LOAD DAYS

Date		Load Percentile	Required DR Interruption Window
7/26/2005	Annual Peak	55/45	9 hours
8/3/2005		55/45	9 hours
7/17/2006		70/30	9 hours
7/31/2006		65/35	10 hours
8/1/2006		95/5	10 hours
8/2/2006	Annual Peak	95/5	10 hours
8/3/2006		60/40	9 hours
8/8/2007	Annual Peak	70/30	8 hours
6/9/2008	Annual Peak	20/80	10 hours
8/10/2009	Annual Peak	20/80	9 hours

TABLE 1

These results indicate that, if the DR limit were raised to 8.5%, the duration window should be expanded to ten hours to ensure that the daily peak is reduced by the full amount of implemented DR.

IV LDA ANALYSIS

The RTO analysis described in Section III examined the likelihood of implementing DR across the RTO due to an overall insufficient level of generation resources. DR may also be implemented to relieve local reliability problems specific to an individual Locational Deliverability Area (LDA).

The three LDAs of primary interest in this study were MAAC (consisting of the PJM Mid-Atlantic zones), Eastern MAAC (consisting of the PSE&G, JCP&L, PECO, AE, DPL and RE zones) and Southwestern MAAC (consisting of the PEPCO and BG&E zones). The ten interruption analysis procedure described above for the RTO was applied to each of these three LDAs with two modifications:

1. LDA reserves were set to the LDA's internal generation plus its Capacity Emergency Transfer Limit (CETL). This is the maximum amount of reserves expected to be available to the LDA during a local capacity emergency.
2. The operating reserve margin at which DR was assumed to be implemented was zero MW. This approach assumes that DR is initiated for LDA related problems only at the point of avoiding an actual loss of load event (or a negative reserve margin).

The results of this analysis for MAAC, EMAAC and SWMAAC are graphically depicted in Figures 6, 7 and 8, respectively. Each figure shows the probability of requiring five or fewer, ten or fewer and 15 or fewer DR interruptions as the amount of DR is increased across the horizontal axis.

FIGURE 6: MAAC

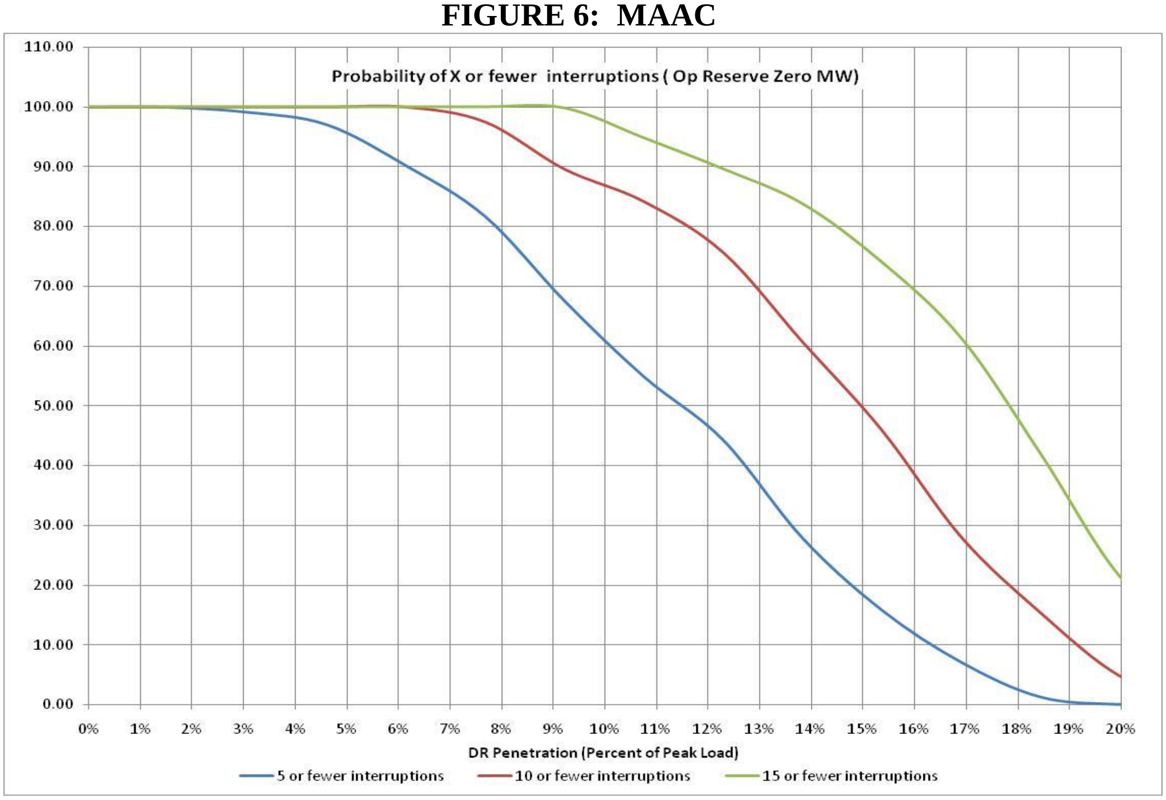


FIGURE 7: EASTERN MAAC

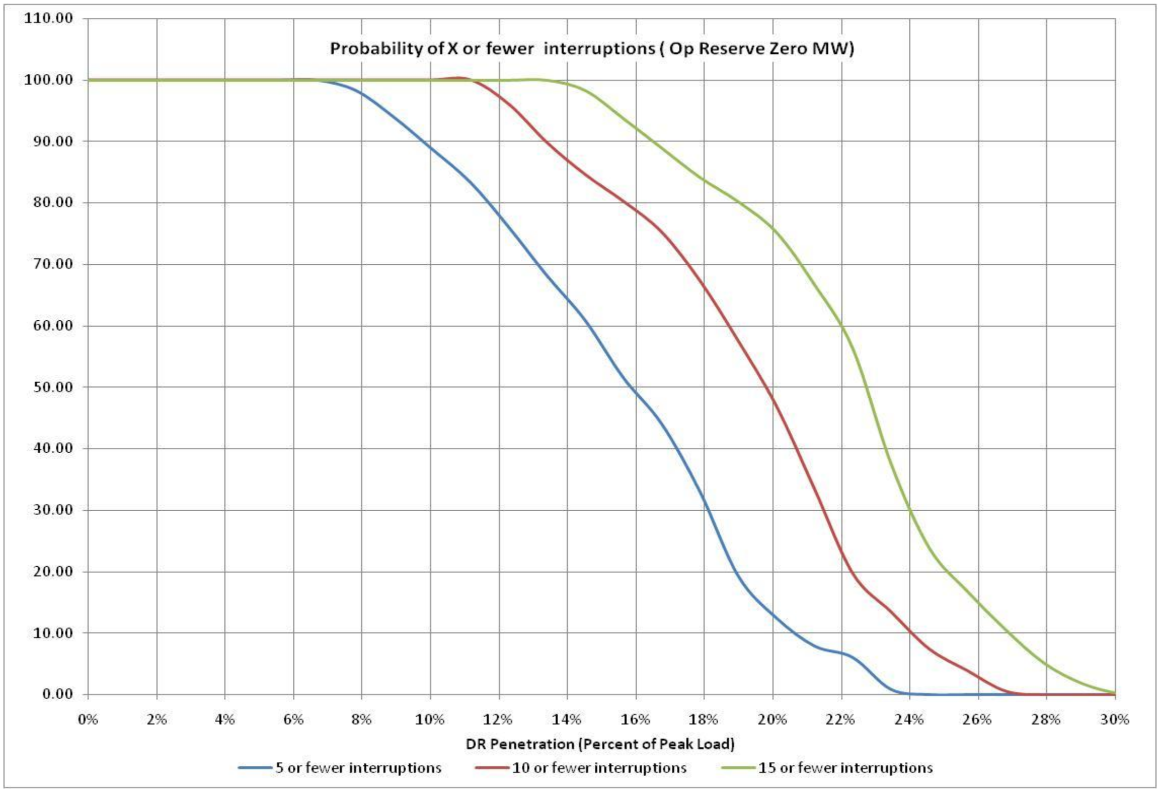


FIGURE 8: SOUTHWEST MAAC

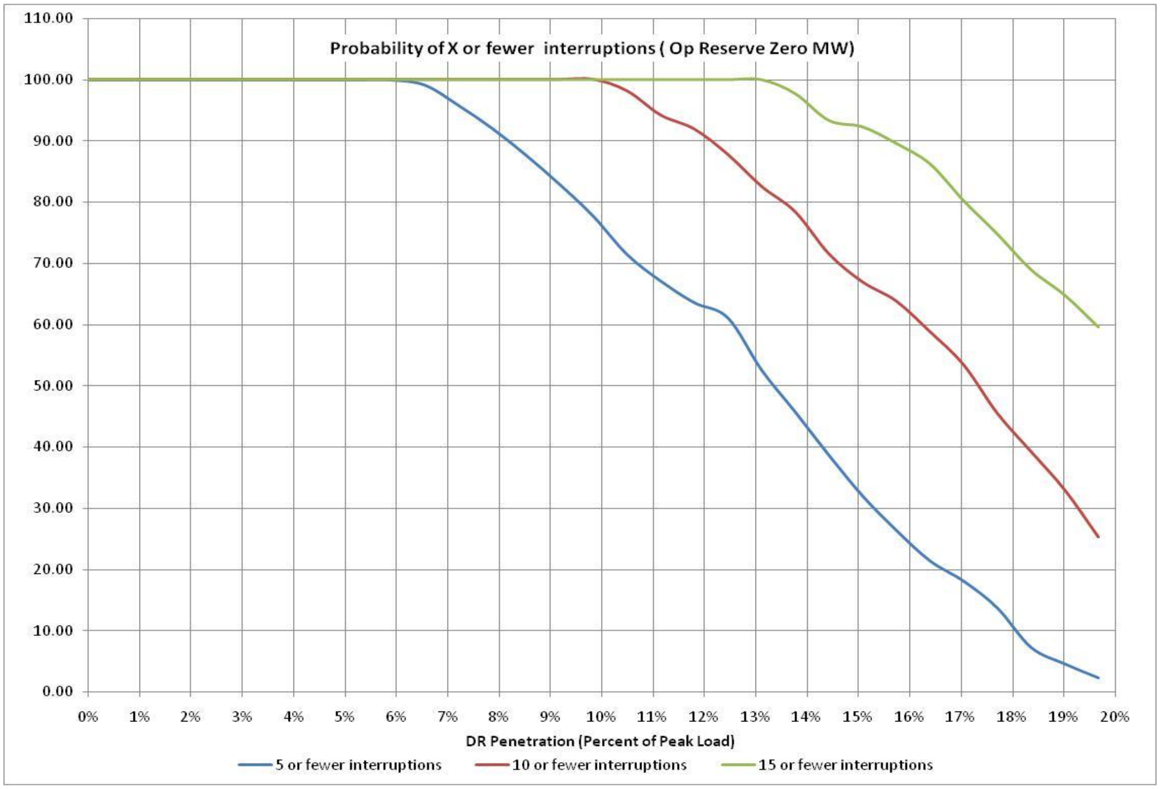


Figure 6 indicates that, based on the same 90% confidence level used in the RTO analysis, the DR penetration level in MAAC should be limited to 9.0% of the forecasted unrestricted MAAC load. The 9.0% value is based on the current requirement of ten interruptions (the red curve in the figure). The "90% confidence" DR limits for Eastern MAAC and Southwestern MAAC are 13.5% and 12.0% based on Figures 7 and 8, respectively.

The green colored curves in Figures 6, 7 and 8 indicate that the DR penetration limits for the three LDAs could be increased if the interruption requirement were raised to 15 per year. The "90% confidence" limit under a 15 interruption per year requirement would be 12.0% for MAAC, 16.5% for Eastern MAAC and 15.5% for Southwestern MAAC.

The DR penetration levels in the LDA analyses are expressed as a percentage of each LDA's non-coincident peak load (NCP). The RPM auctions are conducted using PJM coincident peak loads, so the 9.0%, 13.5% and 12.0% values described above must be converted to a coincident peak load (CP) basis. That conversion is illustrated in Table 2 below.

10 or fewer interruptions					
LDA	DR limit (% of NCP)	NCP Load (MW)	DR Limit (MW)	CP load (MW)	DR Limit (% of CP)
PJMMA	9.0%	64593	5813	62608	**9.3%**
EPJMMA	13.5%	35444	4785	34273	**14.0%**
SPJMMA	12.0%	15244	1829	14715	**12.4%**

TABLE 2

The NCP load values in Table 2 are from Tables B-1, C-3 and C-4 in the 2010 PJM Load Forecast Report and the CP values are from Table B-10 in the same report. All load values are for the 2013/2014 Delivery Year. The rightmost column of Table 2 indicates that the DR limits for MAAC, Eastern MAAC and Southwestern MAAC on a PJM coincident peak load basis are 9.3%, 14.0% and 12.4%, respectively. These LDA limits would need to be observed in addition to the RTO-wide DR limit of 8.5% described in Section III of this report.

The DR limits, assuming a 15 interruption per year requirement, are converted to a PJM coincident peak load basis in Table 3 below.

15 or fewer interruptions					
LDA	DR limit (% of NCP)	NCP Load (MW)	DR Limit (MW)	CP load (MW)	DR Limit (% of CP)
PJMMA	12.0%	64593	7751	62608	**12.4%**
EPJMMA	16.5%	35444	5848	34273	**17.1%**
SPJMMA	15.5%	15244	2363	14715	**16.1%**

TABLE 3

It is important to note that the LDA analysis results are very sensitive to the CETL used to determine the LDA reserve margin. CETL values can change significantly from year to year based on inputs such as the load forecast, generator retirements and the completion or deferral of planned transmission upgrades. As a result, the LDA DR percentage limits could also change significantly from year to year.

V CONCLUSION

Given the current interruption requirements applicable to DR, these study results indicate that the reliability value of DR saturates at an 8.5% penetration level for the RTO. The 8.5% level is based on acceptance of a 90% degree of certainty that DR would not need to be implemented more than ten times in a single year. The study indicates that the DR saturation level would increase to 11% if the interruption requirement were raised from ten to 15 interruptions per year. If an 8.5% RTO limit for DR were established, the interruption window should be expanded to ten hours to ensure the daily peak is not shifted to an off-peak period.

The LDA analysis results indicate that, under current interruption requirements, the reliability value of DR saturates at 9.3% for MAAC, 14.0% for Eastern MAAC and 12.4% for Southwestern MAAC. The LDA analysis considered only DR interruptions that were required to address local, not RTO-wide, reliability problems.

Given these findings and the current DR interruption requirements, PJM recommends the following:

1. The amount of DR RTO-wide should be capped at 8.5% of the forecasted unrestricted peak.

2. The amount of DR in MAAC, Eastern MAAC and Southwestern MAAC should be capped at the levels indicated in the table below. The caps are expressed as a

percentage of each LDA's forecasted PJM coincident peak. It is important to note that these caps are based on each LDA's CETL for the 2013/2014 Delivery Year. The caps could change significantly for other Delivery Years as the CETL is impacted by factors such as generator retirements and the completion or deferral of planned transmission upgrades.

Proposed DR Limits for 2013/14 Delivery Year

LDA	DR Limit
MAAC	**9.3%**
Eastern MAAC	**14.0%**
Southwestern MAAC	**12.4%**

3. Any capacity procured in excess of the IRM or in excess of an LDA's Reliability Requirement could also be DR. This DR would not count toward the cap.

4. The DR interruption window should be expanded from six to ten hours to ensure that the daily peak is reduced by the full amount of implemented DR.

Exhibit 2

Demand Resource Target Calculation Procedures

DR RELIABILITY TARGET ANALYSIS PROCEDURES

The procedures described below are performed on an annual basis prior to each RPM Base Residual Auction. The procedures use the most recent IRM Study model, CETO/CETL models and PJM load forecast model applicable to the Delivery Year (DY) being evaluated.

I LIMITED (10x6) DR PRODUCT

RTO PROCEDURE

Ten Interruption Requirement

Load Model:

1. The summer forecast distributions for the applicable Delivery Year are obtained for the 20 CP (coincident peak) days from the PJM load forecast model. The distributions are based on a range of historical weather scenarios. For a given weather scenario, the CP1 day represents the highest load forecasted for the summer of the forecast year. The CP2 day represents the 2nd highest load forecasted, etc.

2. The median load value from the CP1 day corresponds to the 50/50 forecasted RTO peak for the applicable Delivery Year. The 20 CP distributions are per-unitized on the median of the CP1 day peak. In other words, the ratio of each weather scenario load to the median forecast peak is calculated. Using the ratio calculated, all weather scenario loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows the 20 CP day distributions to be shifted up or down by altering the forecasted summer peak load.

Capacity Model:

3. The PJMRTO cumulative capacity probability table from the most recent IRM Study is obtained. The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance or planned outage. The capacity distribution from the peak week is assumed to be constant for the entire period of 20 CP days. This assumption is made because there are no planned or maintenance outages over the summer period and the generator EFORds are modeled as constant across the Delivery Year.

4. DR is assumed to be a 100% available resource that is available to assist the system whenever PJM operating reserves fall below a certain margin. The operating reserve is thus the margin between load and available capacity at which DR is expected to be invoked. An operating reserve margin of 1,300 MW is assumed for the RTO. This value is documented in Section 2.2 of PJM Manual 13 and represents the RTO's synchronized/spinning reserve requirement that is based on the loss of the largest PJM generating unit.

Analysis:

5. Using the normalized distributions from Step 2, and the cumulative capacity probability table from Step 3, the LOLE is calculated for each of the possible load levels and aggregated. The peak load is iteratively increased until the approved Installed Reserve Margin (with no DR assumed) for the applicable Delivery Year is established. This solved case forms the base case. Note: LOLE is always calculated at zero margin, i.e. load exceeds available capacity (including DR).

6. The 20 CP days from each of the weather scenarios are derived from various weather patterns that simulate the need for invoking DR. At the assumed operating reserve margin, the following occur:

    a. If the margin between load and an available capacity state is greater than the operating reserve, no Loss of Load (LOL) occurs and no DR is invoked.

    b. If the margin between load and an available capacity state is less than the operating reserve, DR is invoked if available. No LOL occurs until the margin becomes less than or equal to zero. For each of the 20 CP days, the first instance (or capacity state) in which the margin falls below the operating reserve is used to determine the probability DR will be invoked on a particular day. For a CP day, DR can be invoked with a probability between zero and one depending on the capacity state at which the margin falls below operating reserve. The probability of DR invocation is calculated for all 20 CP days in a weather scenario and is then summed. This sum represents the expected number of DR invocations in that scenario.

    c. If, after invoking DR, the margin becomes less than zero for certain states, LOL occurs. The LOLE is aggregated for each CP day across all scenarios.

7. Using the 1,300 MW operating reserve margin, the amount of DR is progressively increased. The increase in DR is modeled as 100% available generation and the additional DR replaces an equal amount of generation resources so that the IRM is held constant. Thus, as the amount of DR increases in the system, more generation is displaced and also the expected number of times DR is invoked increases.

8. A histogram of the expected DR invocations from the weather scenarios is developed for each level of DR penetration. The histogram represents the frequency with which DR is implemented X number of times as X is varied from zero to 20. The histogram is then aggregated into a cumulative probability curve that represents the likelihood that DR is implemented X or fewer times. A 90% probability of requiring ten or fewer DR interruptions is used to define the DR Reliability Target. This Target is expressed as a percent of forecasted peak load.

<u>Duration Requirement</u>

1. PJM examines the last five calendar years and identifies any day which is an annual peak load day and/or a day with an unrestricted peak load greater than the 50/50 weather normalized peak and/or a day on which RTO-wide load management was implemented. These days would be most likely to require invocation of DR

2. The unrestricted hourly loads for each of the days identified in step 1 are ranked from highest to lowest. The MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is computed.

3. For each day examined in step 2, the MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is divided by the forecasted 50/50 peak load for that particular summer. The resulting percentages are tabulated for all days that qualify per step 1. The average of these percentages is the DR Reliability Target based on the 6 hour duration requirement. Any day with a peak load well below the 50/50 peak may be excluded from this calculation as it is not representative of a day that would require implementation of DR.

The operative DR Reliability Target is the lower of the targets based on either the ten interruption requirement or the six hour duration requirement.

LDA Procedure

<u>Ten Interruption Requirement</u>

Three LDAs (MAAC, EMAAC and SWMAAC) are examined. The ten interruption analysis procedure described above for the RTO is applied to each of these three LDAs with the two modifications identified in steps 1 and 2 below:

1. LDA reserves are set to the LDA's internal generation plus its Capacity Emergency Transfer Limit (CETL). This is the maximum amount of reserves expected to be available to the LDA during a local capacity emergency. The CETO/CETL cases include energy-only resources and behind-the-meter (BTM) generation.

2. The operating reserve margin at which DR is assumed to be implemented is zero MW. This approach assumes that DR is initiated for LDA related problems only at the point of avoiding an actual loss of load event (or a negative reserve margin).

3. The load model and capacity model for each LDA is developed as described above in steps 1 through 4 for the RTO analysis. The unrestricted load forecast for the LDA is adjusted to include the BTM load. Thus the LDA reserve levels are established using the formula: LDA Reserve Margin = (Installed capacity + CETL) / (Unrestricted Peak Load + BTM load adjustment). The DR Reliability Target is then determined as described in steps 5 through 8 above.

4. Each DR Reliability Target determined in step 3 is converted to a MW amount by multiplying the Reliability Target percentage by each LDA's forecasted non-coincident peak load (NCP). The resulting MW Reliability Target is then divided by each LDA's forecasted coincident peak load (CP). This Reliability Target percentage is used in the RPM auction. The NCP and CP forecasts are obtained from Tables B-1, B-10, C-3 and C-4 from the most recent PJM Load Forecast Report.

Duration Requirement

1. PJM examines the last five calendar years and identifies any day which is an LDA annual peak load day and/or a day with an unrestricted peak load greater than the 50/50 weather normalized LDA peak and/or a day on which load management was implemented in that particular LDA. These days would be most likely to require invocation of DR

2. The unrestricted hourly loads for each of the days identified in step 1 are ranked from highest to lowest. The MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is computed.

3. For each day examined in step 2, the MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is divided by the forecasted 50/50 LDA peak load for that particular summer. The resulting percentages are tabulated for all days that qualify per step 1. The average of these percentages is the DR Reliability Target based on the 6 hour duration requirement. Any day with a peak load well below the 50/50 LDA peak may be excluded from this calculation as it is not representative of a day that would require implementation of DR.

4. Each DR Reliability Target determined in step 3 is converted to a MW amount by multiplying the Reliability Target percentage by each LDA's forecasted non-coincident peak load (NCP). The resulting MW Reliability Target is then divided by each LDA's forecasted coincident peak load (CP). This Reliability Target

percentage is used in the RPM auction. The NCP and CP forecasts are obtained from Tables B-1, B-10, C-3 and C-4 from the most recent PJM Load Forecast Report.

The operative DR Reliability Target is the lower of the two targets based on either the ten interruption requirement or the six hour duration requirement.

II EXTENDED SUMMER DR PRODUCT

This section details the procedure used to determine the DR Reliability Target associated with a demand resource product that is available for interruption an unlimited number of times from May 1 through October 31 but is not interruptible over the November 1 through April 30 time period. Each interruption may last up to ten hours. The criterion to establish the Reliability Target is to ensure that the Extended Summer DR product does not have a negative impact on system reliability. The procedure uses the most recent IRM Study model, CETO/CETL models and PJM load forecast model applicable to the Delivery Year being evaluated.

RTO PROCEDURE

Load Model:

1. The daily load forecast distributions for the applicable Delivery Year are obtained for all weekdays from the PJM load forecast model. The distributions are based on a range of historical weather scenarios. This results in approximately 260 daily load distributions.
2. The maximum load value from each weather scenario's summer period (June 1 – August 31) is determined. The median of the distribution of all these maximum load values represents the 50/50 forecasted summer RTO peak for the applicable Delivery Year.
3. The daily load distributions from step 1 are per-unitized on the 50/50 peak load value determined in step 2. In other words, the ratio of each weather scenario load to the median forecast peak is calculated. Using the ratio calculated, all weather scenario loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows all the daily load distributions to be shifted up or down by altering the forecasted summer peak load.

Capacity Model:

4. The PJMRTO cumulative capacity probability table from the most recent IRM Study is obtained for all 52 weeks of the applicable Delivery Year. The cumulative capacity probability table represents the distribution of available

capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance or planned outage.

5. The daily load distributions from step 3 are mapped to the corresponding weekly capacity distribution from step 4.

Analysis:

6. As described in step 3, the daily load distributions are iteratively shifted to equal the IRM established for the applicable DY.

7. A reference annual LOLE is determined based on the daily load distributions from step 6 and the capacity distributions from step 4. The resulting case is the Base Case.

8. To simulate the impact of summer-only DR, varying amounts of DR (expressed as a percent of the unrestricted peak load) are modeled to be interruptible from May 1 through October 31 while being unavailable for the November 1 through April 30 period. The DR is represented as a 100% available resource and is assumed to displace an equal amount of 100% available generation for the entire year.

9. At each DR amount, the annual LOLE is determined and the percent increase in risk from the reference annual LOLE is calculated.

10. The DR Reliability Target is equal to the DR amount at which the percent increase from the reference LOLE computed in step 9 is 10%. The DR Reliability Target in MW is expressed as a percent of the forecasted unrestricted peak.

LDA Procedure

Load Model:

1. The daily load forecast distributions for the applicable Delivery Year are obtained for all weekdays from the PJM load forecast model. The distributions are based on a range of historical weather scenarios. This results in approximately 260 daily load distributions.

2. The maximum load value from each weather scenario's summer period (June 1 – August 31) is determined. The median of the distribution of all these maximum load values represents the 50/50 forecasted summer LDA peak for the applicable Delivery Year.

3. The daily load distributions from step 1 are per-unitized on the 50/50 peak load value determined in step 2. In other words, the ratio of each weather scenario load to the median forecast peak is calculated. Using the ratio calculated, all weather scenario loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows all the daily load

distributions to be shifted up or down by altering the forecasted summer peak load. The load distributions are adjusted to match a load level equal to the unrestricted forecasted LDA peak plus a behind-the-meter load adjustment.

Capacity Model:

4. The cumulative capacity probability table from the most recent CETO/CETL Study is obtained for all 52 weeks of the applicable Delivery Year. (The CETO/CETL cases include energy-only resources and behind-the-meter generation.) The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance or planned outage.

5. The daily load distributions from step 3 are mapped to the corresponding weekly capacity distribution from step 4.

Analysis:

6. A Base Case is established that sets the reserve margin based on the following formula: LDA Reserve Margin = (Installed capacity + CETL) / (Unrestricted Peak Load + behind-the-meter load adjustment).

7. A reference annual LOLE is determined based on the daily load distributions from the Base Case established in step 6 and the capacity distributions from step 4.

8. To simulate the impact of summer-only DR, varying amounts of DR (expressed as a percent of the unrestricted peak load) are modeled to be interruptible from May 1 through October 31 while being unavailable for the November 1 through April 30 period. The DR is represented as a 100% available resource and is assumed to displace an equal amount of 100% available generation for the entire year.

9. At each DR amount, the annual LOLE is determined and the percent increase in risk from the reference annual LOLE is calculated.

10. The DR penetration percentage at which the percent increase from step 9 is equal to 10% is determined. The DR Reliability Target in MW is expressed as a percentage of the forecasted unrestricted peak (adjusted by BTM load) used in the study.

11. The DR penetration percentage determined in step 10 is then multiplied by the LDA's forecasted non-coincident peak load (NCP). The resulting MW amount is then divided by the LDA's forecasted coincident peak load (CP) to determine the LDA Reliability Target as a percent of the LDA's CP. This Reliability Target, expressed as a percentage of the LDA's forecasted CP load, is used in the RPM auction. The NCP and CP forecasts are obtained from Tables B-1, B-10, C-3 and C-4 from the PJM Load Forecast Report.

Exhibit 3

Demand Resource Target Calculation Illustrations

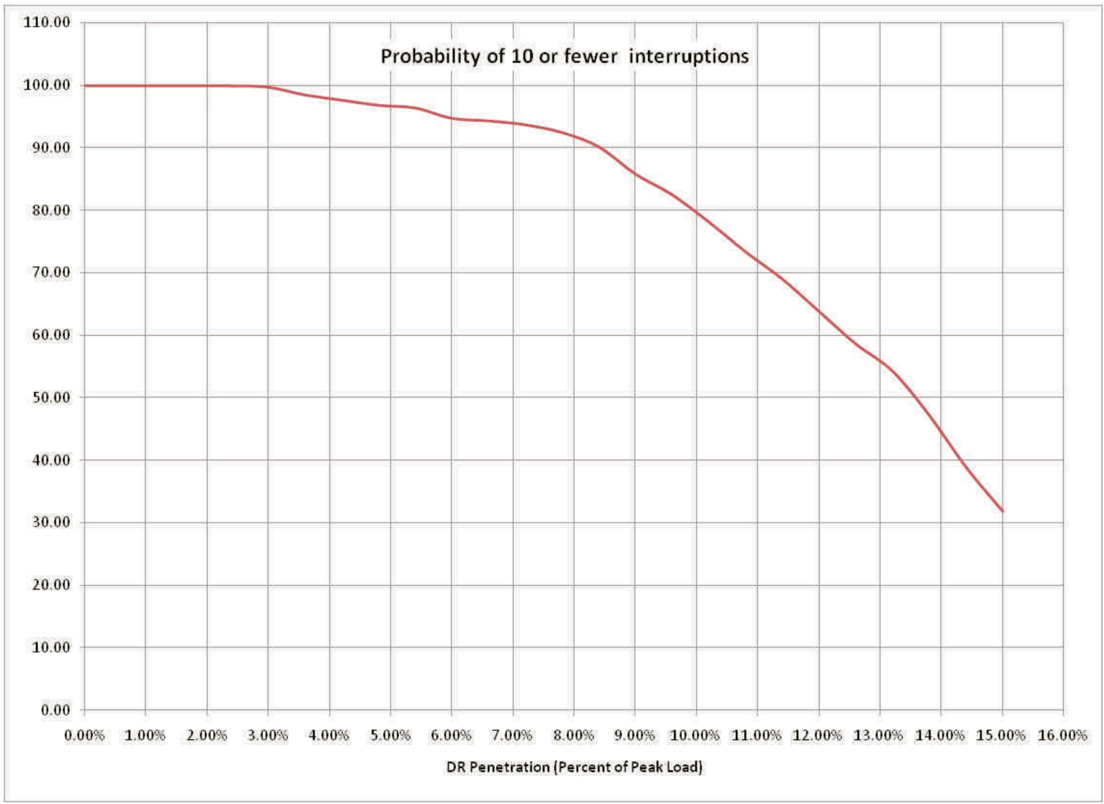
DR RELIABILITY TARGET ANALYSIS
RESULTS FOR 2013/2014 DELIVERY YEAR

These analysis results are based on input data from the 2010 PJM Load Forecast Report, the 2009 PJM Installed Reserve Margin Study and 2013/2014 CETO/CETL Cases.

I LIMITED (10x6) DR PRODUCT

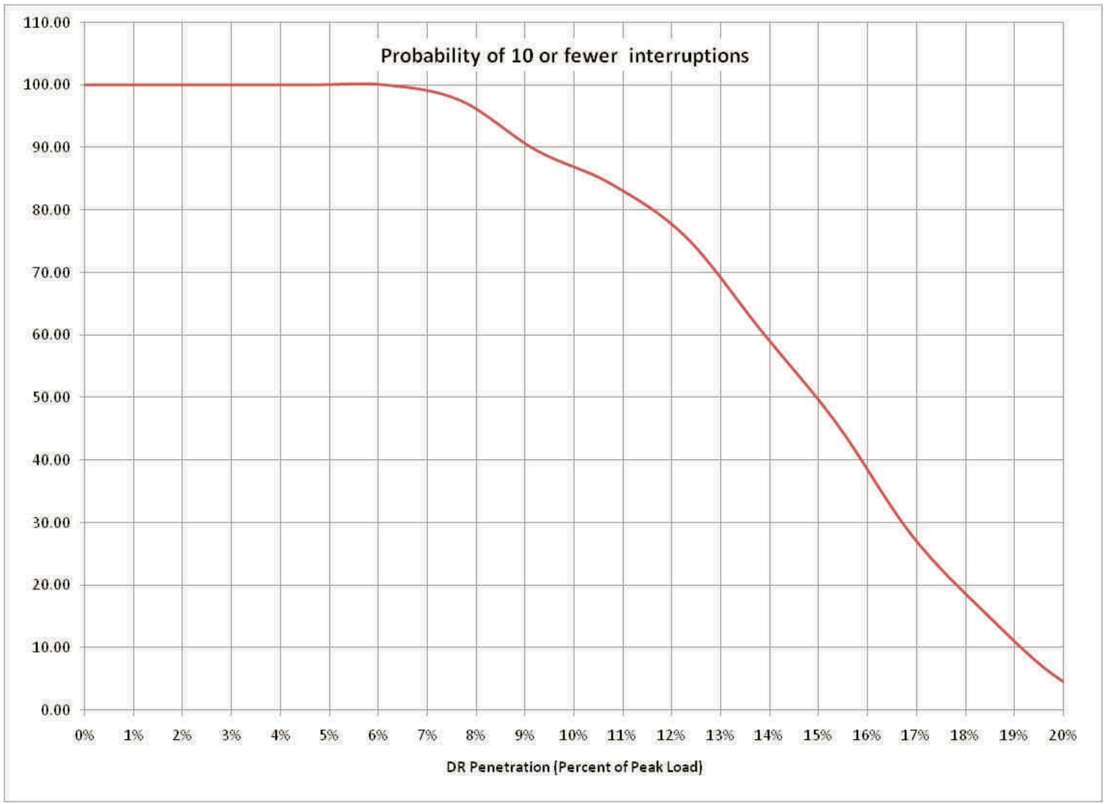
TEN INTERRUPTION ANALYSIS

PJM RTO

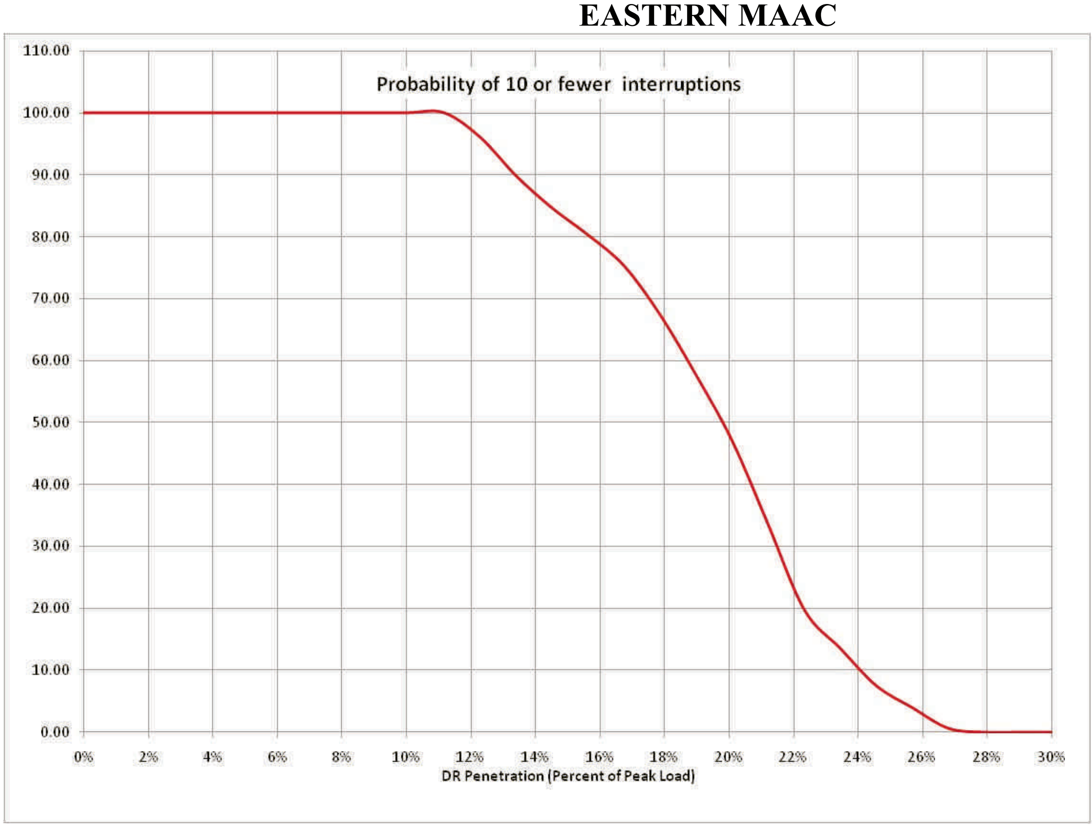


Based on a 90% threshold, the DR Reliability Target for the RTO is 8.5% of the forecasted unrestricted peak load.

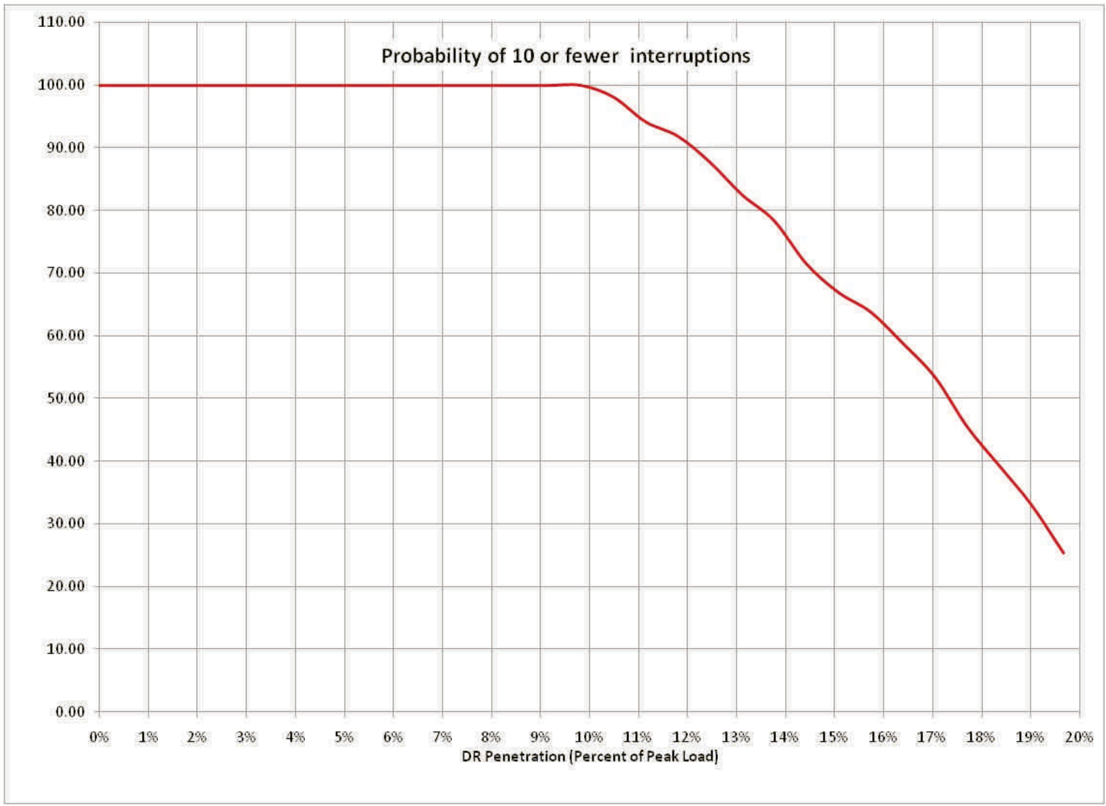
MAAC



EASTERN MAAC



SOUTHWEST MAAC



The DR penetration levels on the graphs above are expressed as a percentage of the LDA's non-coincident peak load (NCP). These values are converted to a percentage of each LDA's PJM coincident peak load (CP) in the table below.

LDA ANALYSIS RESULTS

10 or fewer interruptions					
LDA	DR limit (% of NCP)	NCP Load (MW)	DR Limit (MW)	CP load (MW)	DR Limit (% of CP)
PJMMA	9.0%	64593	5813	62608	**9.3%**
EPJMMA	13.5%	35444	4785	34273	**14.0%**
SPJMMA	12.0%	15244	1829	14715	**12.4%**

SIX HOUR DURATION ANALYSIS

PJM RTO

DR CAP FOR SELECTED LOAD DAYS 2005-2009			
Date		Load Percentile	Cap for 6 Hour Duration
7/26/2005	Annual Peak	55/45	4.8%
8/3/2005		55/45	5.3%
7/17/2006		70/30	4.5%
7/31/2006		65/35	4.5%
8/1/2006		95/5	5.0%
8/2/2006	Annual Peak	95/5	5.0%
8/3/2006		60/40	3.6%
8/8/2007	Annual Peak	70/30	5.1%
6/9/2008	Annual Peak	20/80	3.8%
8/10/2009	Annual Peak	20/80	5.6%
Average excl 2008,2009			**4.7%**

MAAC

DR CAP FOR SELECTED LOAD DAYS 2005-2009				
Date	Annual Peak	Load Management	Above 50/50	Cap for 6 Hour Duration
7/27/2005	X	X	X	7.0%
8/4/2005		X		4.1%
7/17/2006			X	4.6%
7/18/2006			X	5.3%
8/1/2006			X	5.8%
8/2/2006	X	X	X	4.3%
8/3/2006		X	X	4.6%
8/8/2007	X	X	X	7.0%
6/10/2008	X			6.2%
8/10/2009	X			5.9%
Values below exclude 2008 and 2009				
Min				4.1%
Max				7.0%
Average				**5.3%**

EASTERN MAAC

DR CAP FOR SELECTED LOAD DAYS 2005 - 2009				
Date	Annual Peak	Load Management	Above 50/50	Cap for 6 Hour Duration
7/27/2005	X	X	X	9.0%
8/4/2005		X		5.3%
7/17/2006			X	4.9%
7/18/2006			X	6.2%
8/1/2006			X	6.0%
8/2/2006		X	X	4.4%
8/3/2006	X	X	X	5.3%
8/8/2007	X	X	X	7.3%
6/10/2008	X		X	6.6%
8/10/2009	X			6.1%
Values below exclude 2009				
Min				4.4%
Max				9.0%
Average				**6.1%**

SOUTHWEST MAAC

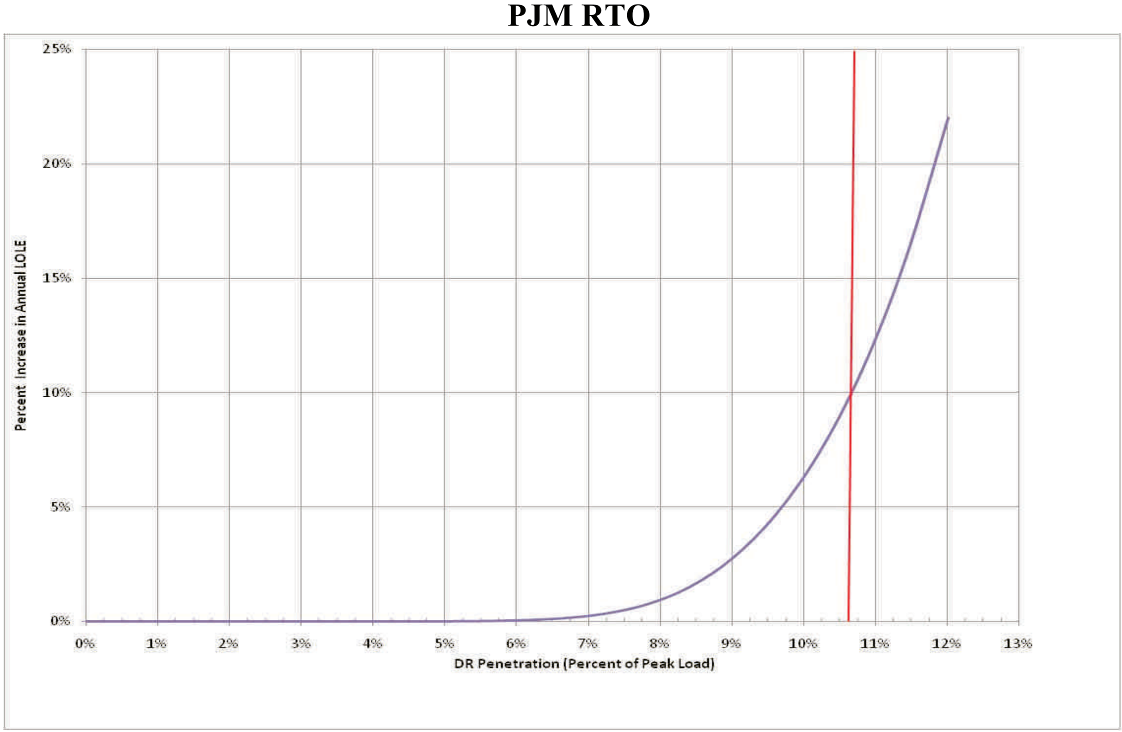
DR CAP FOR SELECTED LOAD DAYS 2005 - 2009				
Date	Annual Peak	Load Management	Above 50/50	Cap for 6 Hour Duration
7/26/2005			X	5.2%
7/27/2005	X	X	X	7.5%
8/4/2005		X		5.8%
8/12/2005			X	6.1%
8/1/2006			X	6.2%
8/2/2006		X	X	5.1%
8/3/2006	X	X	X	5.8%
8/8/2007	X	X	X	5.9%
6/10/2008	X			9.9%
8/10/2009	X			5.9%
Values below exclude 2008 and 2009				
Min				5.1%
Max				7.5%
Average				**6.0%**

The DR Targets in the tables above are expressed as a percentage of the LDA's non-coincident peak load (NCP). These values are converted to a percentage of each LDA's PJM coincident peak load (CP) in the table below.

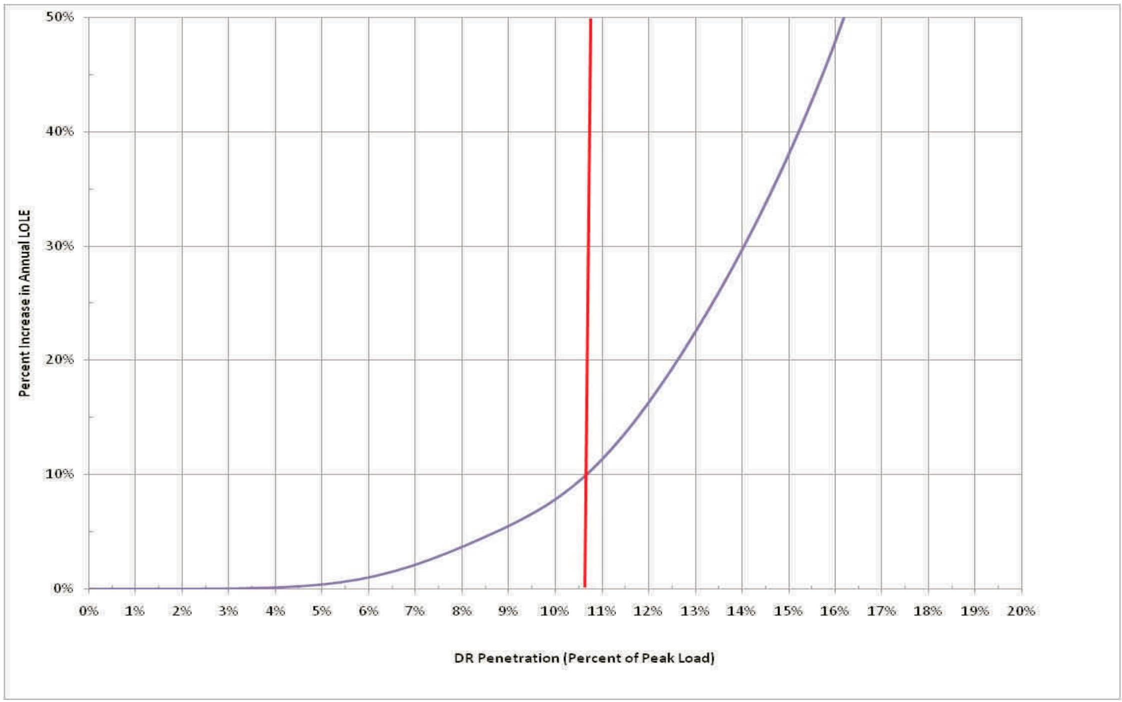
Six Hour Interruption Duration					
LDA	DR limit (% of NCP)	NCP Load	DR Limit (MW)	CP load (Table B-10)	DR Limit (% of CP)
MAAC	5.3%	64593	3423	62608	**5.5%**
EMAAC	6.1%	35444	2162	34273	**6.3%**
SPJMMA	6.0%	15244	915	14715	**6.2%**

II EXTENDED SUMMER DR PRODUCT

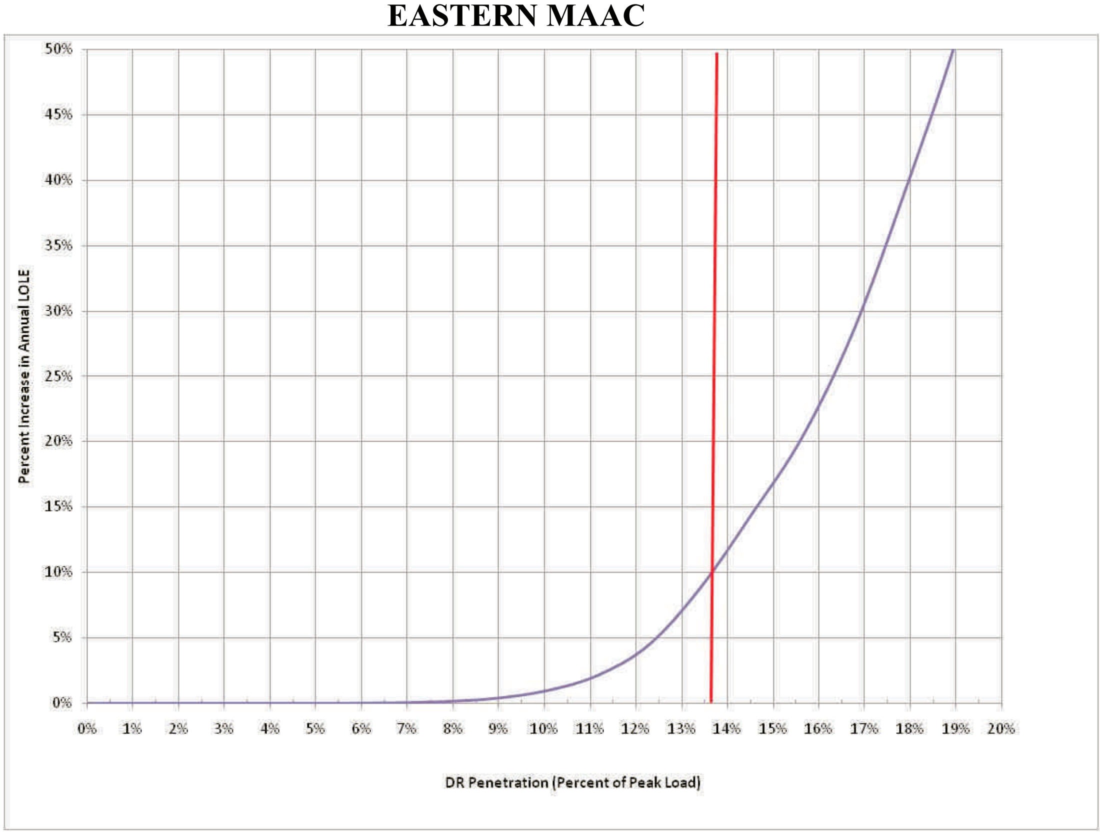
PJM RTO



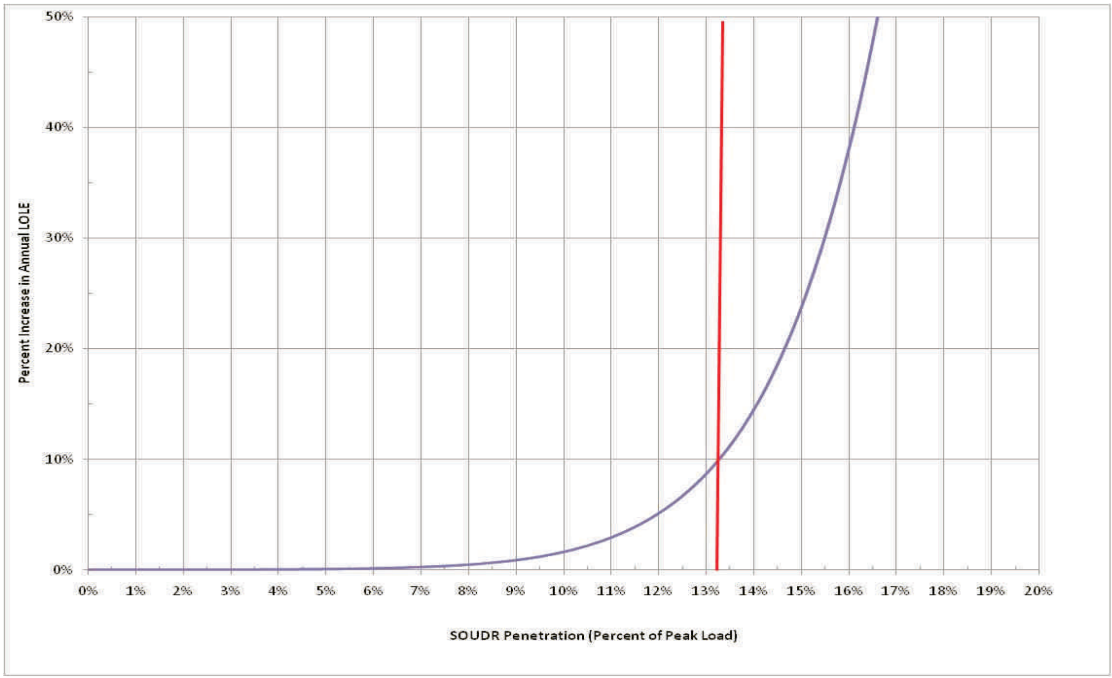
MAAC



EASTERN MAAC



SOUTHWEST MAAC



The Extended Summer DR penetration levels on the graphs above are expressed as a percentage of the LDA's non-coincident peak load (NCP). These values are converted to a percentage of each LDA's PJM coincident peak load (CP) in the table below.

EXTENDED SUMMER DR RESULTS

LDA	**Summer DR (Interruptible from May-October for up to 10 Hours per Interruption)**	
	Threshold as % NCP	Threshold as % CP
PJMRTO	10.6	**10.6**
MAAC	10.75	**11.1**
EMAAC	13.75	**14.2**
SWMAAC	13.25	**13.7**

Exhibit 2

September 2018 LECR Presentation

Limited Energy Capability Resource (LECR) Duration Requirement for the Capacity Market

Scott Benner

Sr. Lead Engineer, PJM

Market Implementation Committee – Electric Storage Resources

September 14, 2018

Copyright Information

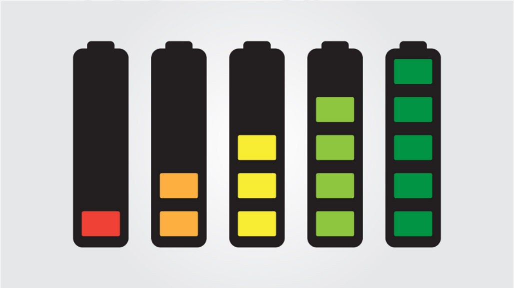
- This presentation is based on a paper submitted to IEEE for review.
- Publication Title: 2019 IEEE PES Innovative Smart Grid Technologies Conference N.A. (ISGT N.A.)
- Article Title: Limited Energy Capability Resource Duration Requirement for Participation in PJM Capacity Market
- Author(s): Aramazd Muzhikyan, Laura Walter, Scott Benner, Anthony Giacomoni

Outline

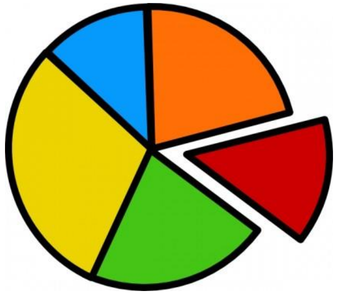
- Problem Statement
- The Method of Equivalent Duration
- Incorporation of Behind the Meter Solar Data
- LECR Capacity Range
- Equivalent Duration for Different LECR Penetration
- Peak Start and End Consideration for DR
- Conclusions

Research Questions

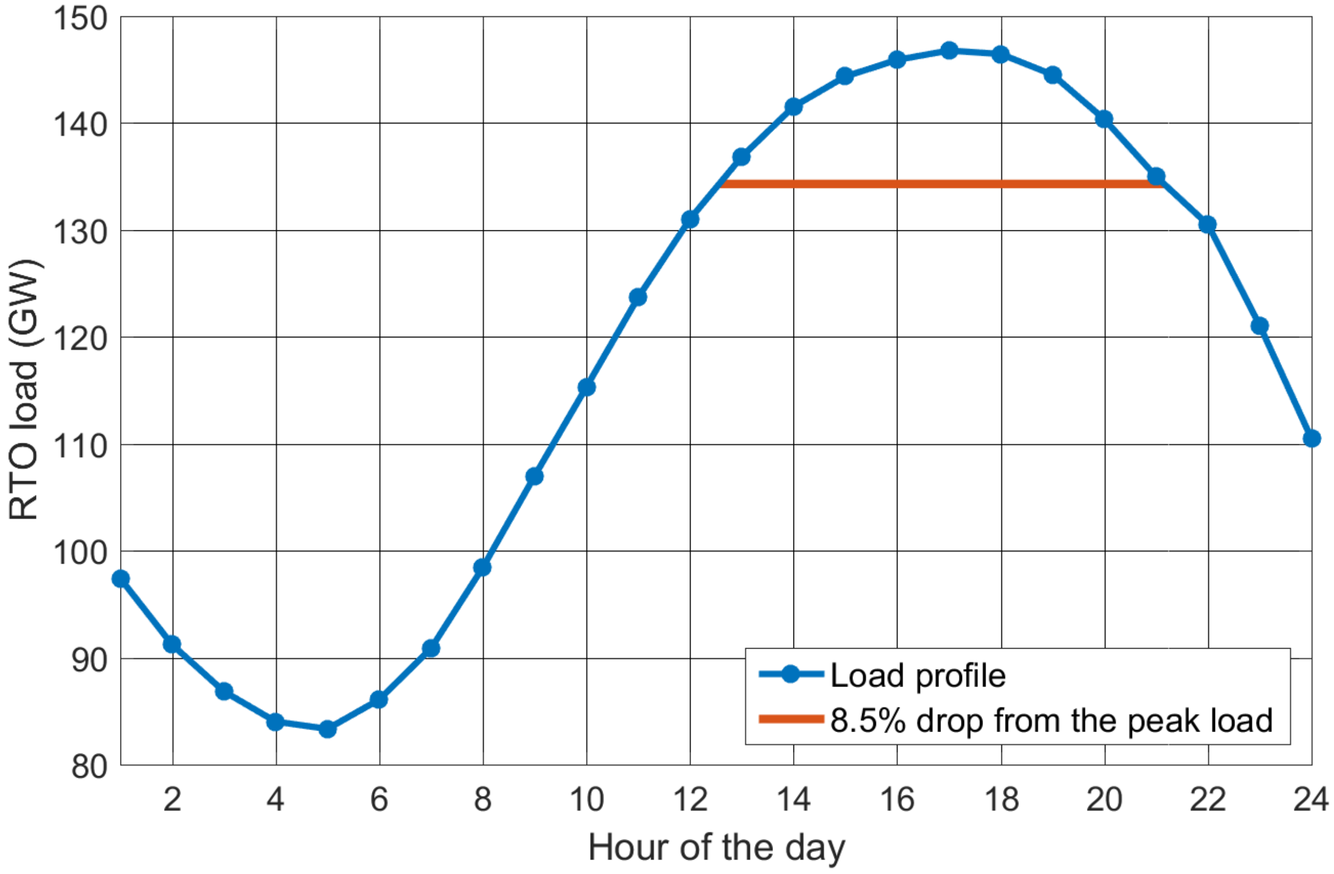
What should the duration requirement for electric storage be for participating in the capacity market?



How the capacity of electric storage should be calculated in the capacity market?



What's the maximum electric storage capacity the system can accommodate?

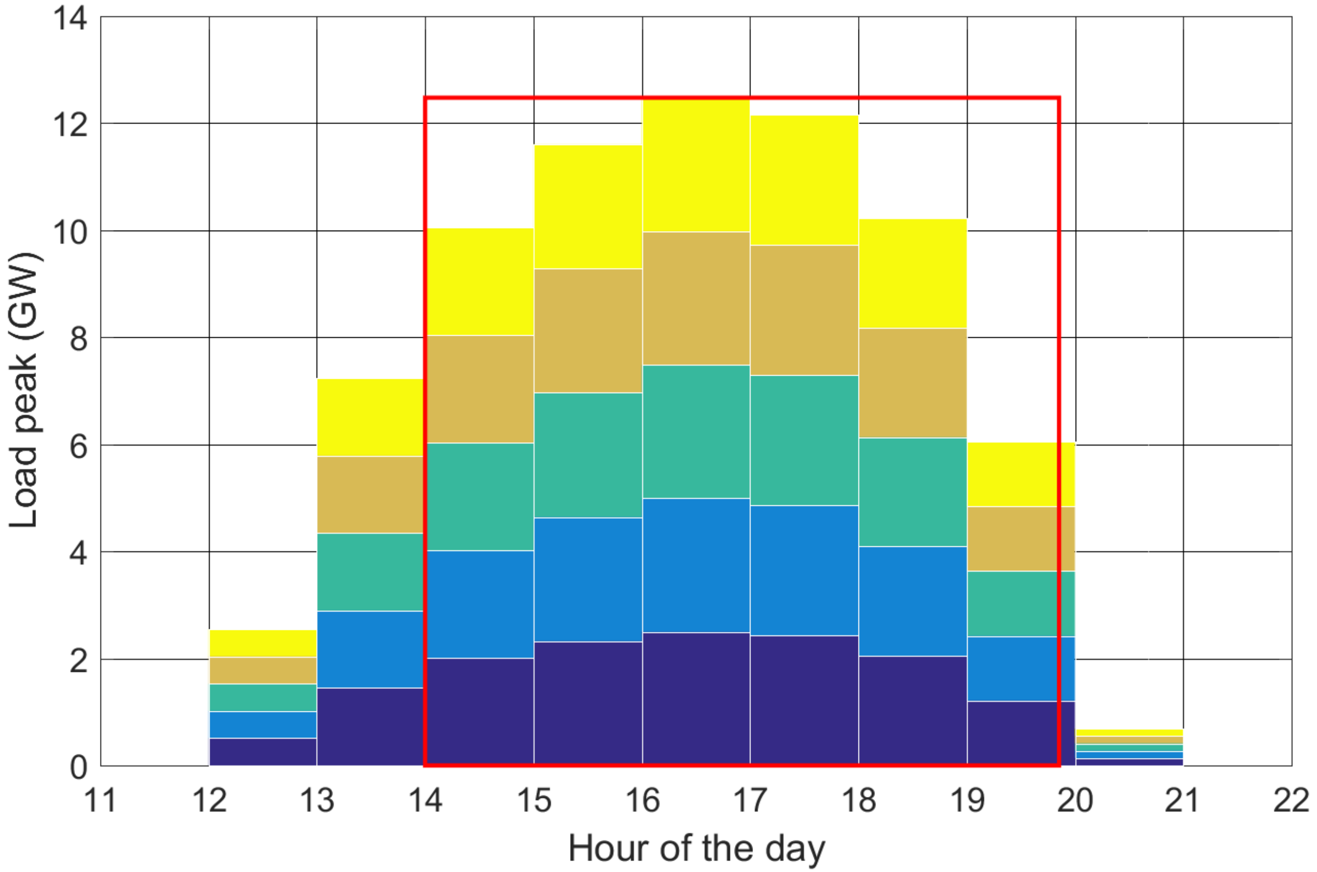


The procured LECR capacity is assumed to be 8.5% of the peak, represented by the red line.

The conventional wisdom suggests a 9-hour duration requirement which translates into LECR with 12.47x9 = 112.23 GWh energy capacity.

The total energy in the peak is 73.03 GWh.

The Method of Equivalent Duration

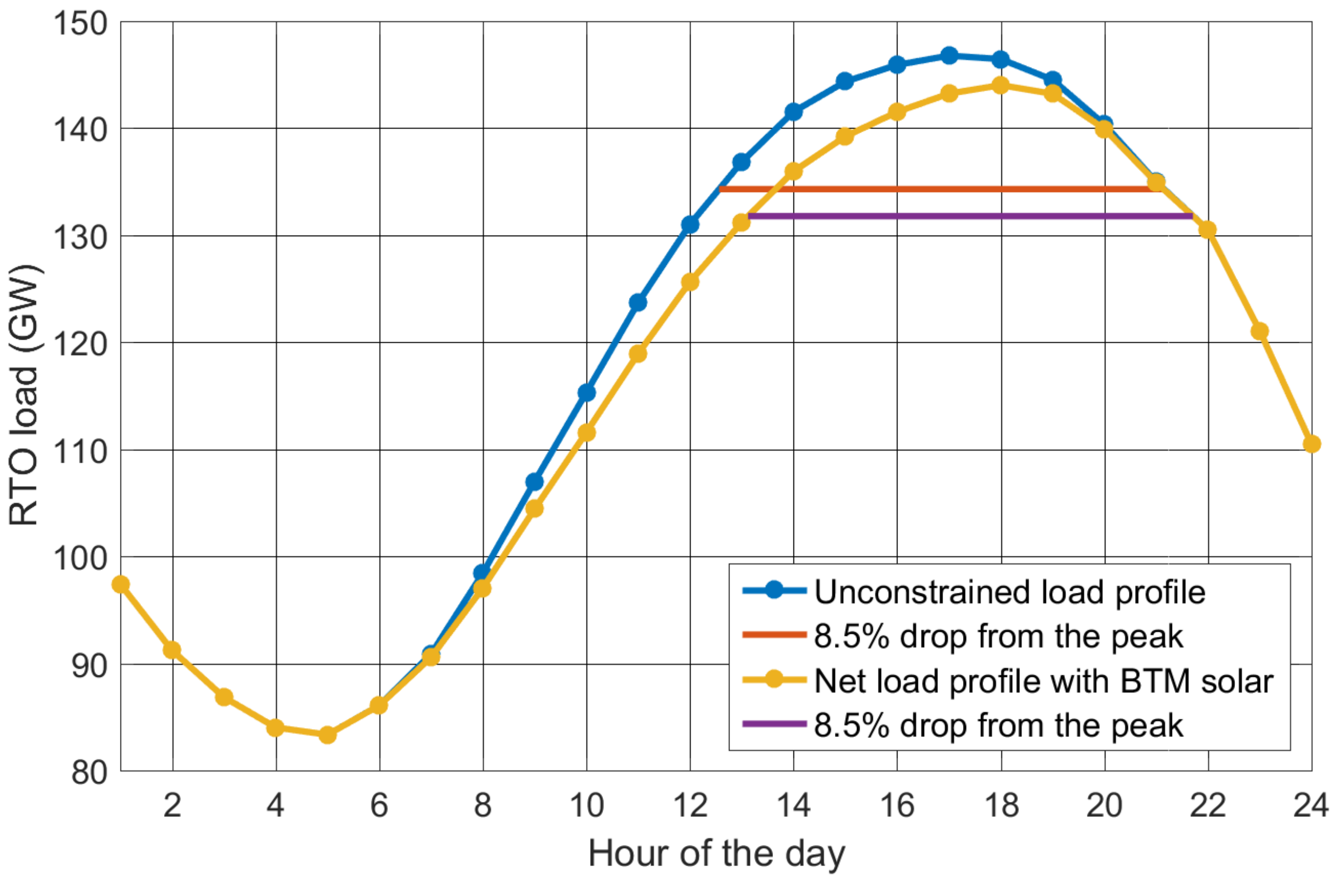


The peak is sliced into geometrically similar strips, where individual pieces follow the same shape but have different heights.

The capacity compensation is defined by the maximum power the resource provides while following the required shape.

The concept of equivalent duration is defined as the amount of energy in the peak divided by its maximum MW value.

The Effect of BTM Solar on the Peak

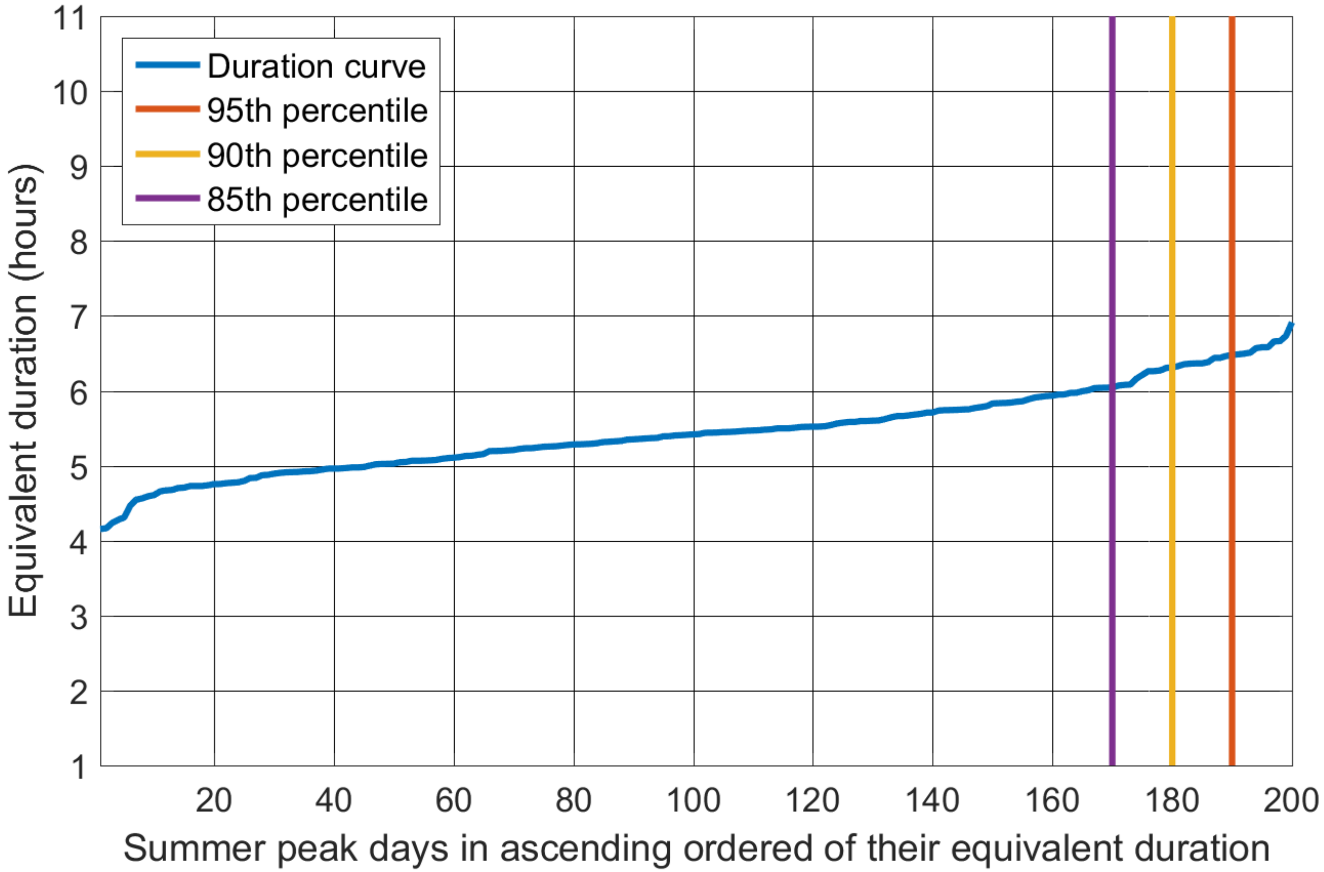


Incorporation of BTM solar moves the peak more to the right and reducing its maximum MW value.

These effects are amplified as more BTM solar is added.

BTM solar integration leaves equivalent duration estimations largely unchanged.

Equivalent Duration Percentile Curve

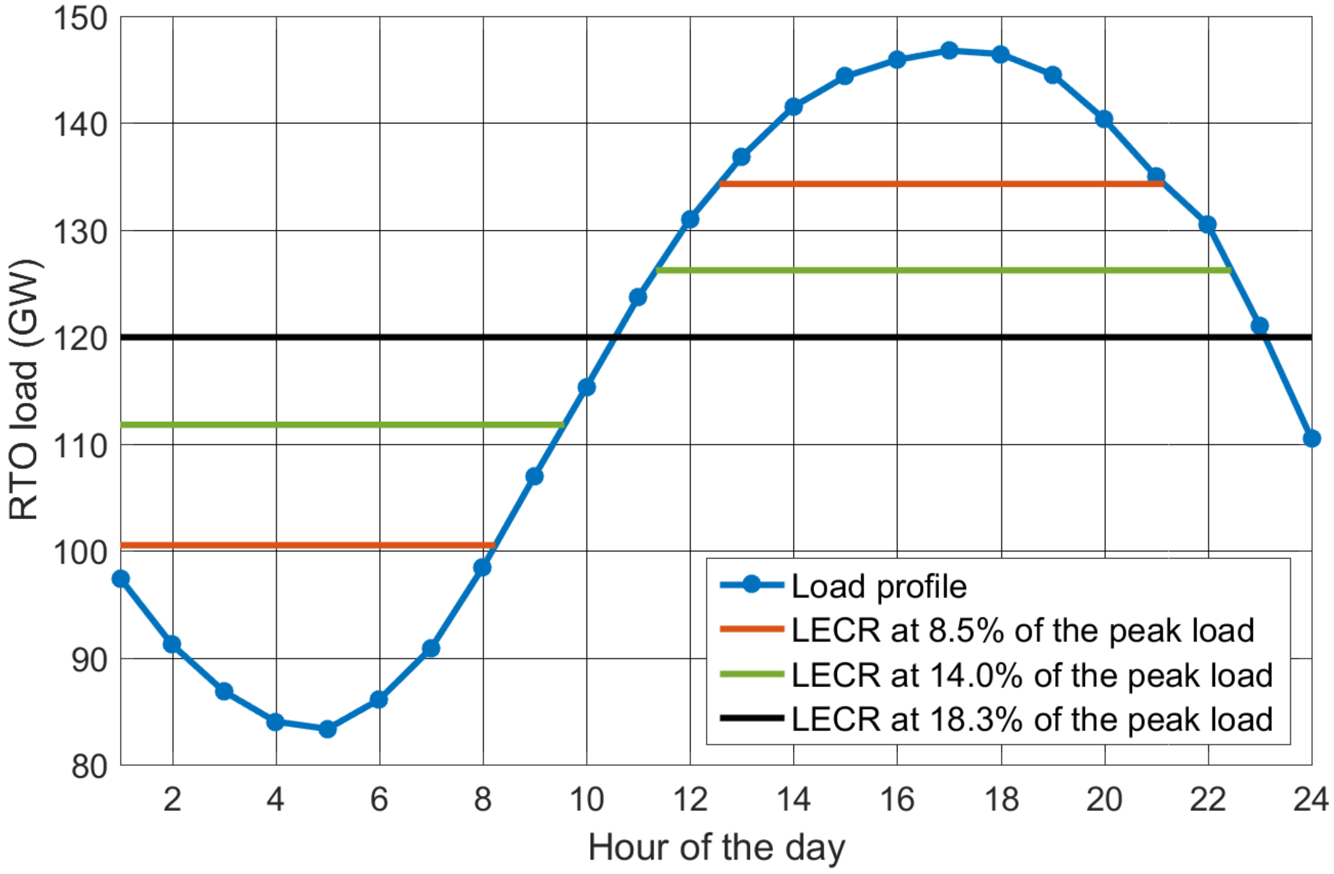


The data pool is expanded by including load profiles for the last 10 years of 2008-2017.

Total of 20x10=200 summer peak days are analyzed to obtain their equivalent duration values.

For 8.5% LECR penetration, the equivalent duration reaches a maximum of 7 hours.

LECR Capacity Range Calculation

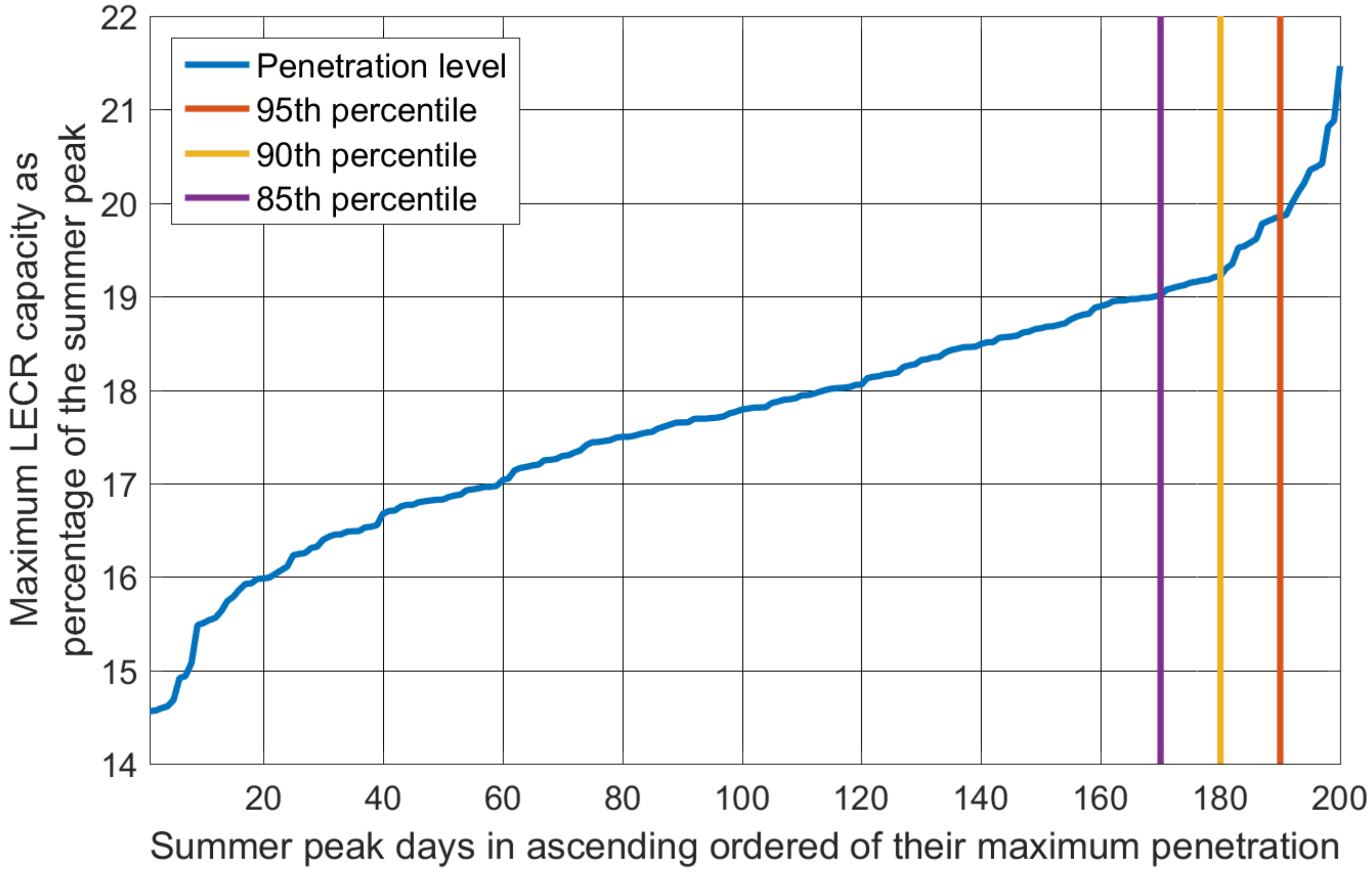


The energy stored during the valley period is used to serve the peak.

As the percentage of LECR in the system increases, both peak and valley widen.

At some point, the intervals of charging and discharging occupy the whole day.

LECR Capacity Range Estimates

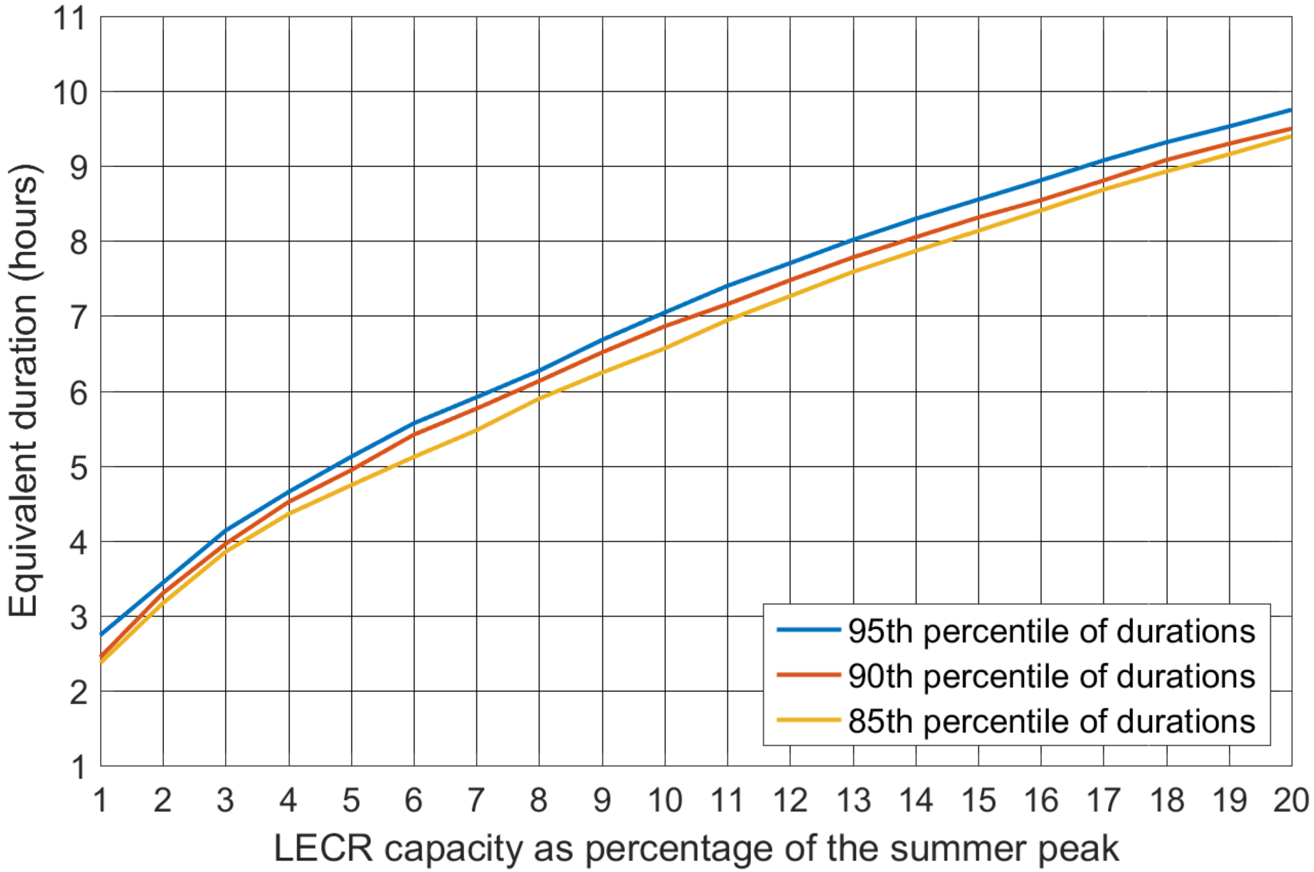


Capacity range estimates are obtained for the 200 summer peak days considered here.

The system can economically accommodate up to about 20% of LECR.

Additional LECR capacity beyond 20% will be used in less than 5% of instances.

Equivalent Duration Requirements

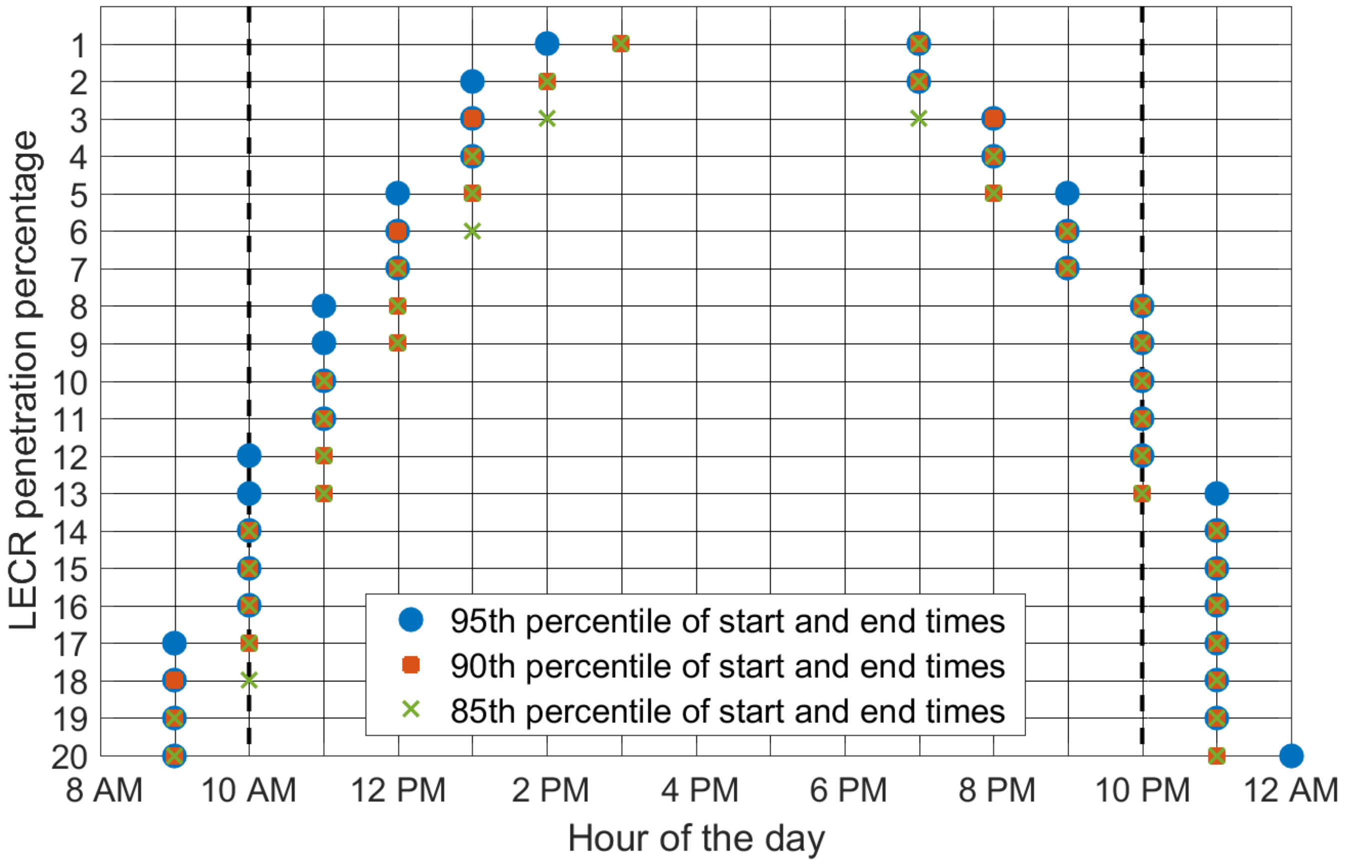


Equivalent durations are obtained for up to 20% LECR penetration.

4-hour duration requirement limits the LECR capacity to about 3% of the annual peak.

When LECR penetration reaches 20%, the equivalent duration is about 10 hours.

Peak Start and End Times



CP DR resources are required to be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM in the summer.

The system with BTM solar corresponding to 2028 ICAP projections can accommodate maximum of 12% LECR.

Conclusions

- Limited Energy Capability Resources (LECR) participating in the capacity market should meet 10-hour equivalent duration requirement.
- 10-hour duration requirement allows the system to reasonably accommodate maximum of 20% LECR.
- At 4-hour equivalent duration requirement, the system is able to accommodate less than 5% LECR.