NYISO Meter Data Study Final Report- December 8, 2017

Prepared for the New York Independent System Operator, Inc. (NYISO) by
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Disclaimer

The thoughts, analysis, and opinions expressed are that of E-Cubed Policy Associates, LLC, and not necessarily those of the NYISO, or any other ISO/RTO market referenced herein.

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Executive Summary

In 2016 the NYISO undertook an initiative to fully integrate Distributed Energy Resources (DER) into the wholesale Energy, Ancillary Service, and Capacity Markets it administers. The NYISO's initiative seeks to capture the reliability benefit DER provide the bulk power system, as well as their economic value to wholesale markets. The NYISO's effort aligns with the New York State Public Service Commission's (NYPSC) *Reforming the Energy Vision* (REV) proceeding initiated in April 2014,[1] which hopes to create a market to increase distribution system deployment of DER to promote efficiency and reliability, to empower customers to better manage their energy bills, and to provide greater fuel diversity.[2]

This Meter Data Study report examines issues identified in the Meter Policies track in the NYISO's *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets (DER Roadmap)*, including:

- Meter data policies and the role of entities providing meter services for DER as may be required;
- Baselines for DER as required and modification to existing baselines if needed;
- Potential for the sampling of a subset of DERs for establishing baselines and for market settlement in the energy, capacity and ancillary services markets;
- Interactions of baselines and DER aggregation; and
- Simultaneous participation in both retail and wholesale markets.

This Meter Data Study leverages the experience of wholesale market policies related to demand response participation and the experience of other ISO/RTO markets including PJM, ISO New England, and the California ISO.

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[1] *See*, New York Public Service Commission (NYPSC), *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* Case 14-M-0101, April 25, 2014. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9CF883CB-E8F1-4887-B218-99DC329DB311}, *See also*, New York Department of Public Service (NY DPS), Case 14-M-0101, *Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal* (Apr. 24, 2014), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5A9BDBBD-1EB7-43BE-B751-0C1DAB53F2AA} (*REV Staff Report and Proposal*).

[2] *REV Staff Report and Proposal* p. 6.

Key Findings and Recommendations

Metering and Meter Data Policies

- Continue to allow third party entities to provide metering services for wholesale DR and DER participation. This is consistent with current NYISO policy and other ISO/RTO policies.
- Work with incumbent utilities on a short-term M&V and monitoring approach. The incumbent utilities can provide data and information to the NYISO on metering or meter data issues they are seeing from DR and DER through their metering and billing activities that can help support NYISO staff and resources on M&V efforts.
- Develop an automated monitoring tool and protocols as a long term M&V and monitoring approach. This will place a greater burden on NYISO staff up front to develop the IT infrastructure and protocols for monitoring data, but once in place would reduce the needed staff time to engage in effective monitoring and M&V of metering and meter data once in place.
- Use incentives rather than administrative mechanisms to enforce metering and meter data standards. This path is consistent with the track taken by PJM and where ISO-NE is moving toward. Enforcing standards through the ability to foreclose market participation until metering and meter data standards are met is a powerful incentive to ensure meter data accuracy.

Energy Market Baselines

- Maintain the current “5 of 10” baseline with weather adjustments used in the NYISO’s Demand Response programs as it has been shown in previous studies to be an accurate estimate of energy consumption.
- Maintain the cap on weather adjustments currently in place at +/-20 percent to reflect changes in weather driven load, but also to guard against strategic behavior.
- Any baseline that is used should satisfy an accuracy measure of no greater than a 20 percent relative root mean square error. Highly variable loads, especially those with on-site generation or storage contributing toward load variation, should be able to explore other baselines to achieve the accuracy recommendation.
- Require on-site generation or storage to be directly metered. Directly metering on-site generation or DER can help in discerning whether the generation/DER is being used regularly to help meet facility load, or whether it is only used to reduce load during emergency or high price events.

- In the short-term, dual participation of resources receiving compensation under the NYPSC VDER Tariff should not be permitted to participate in the NYISO energy market until there is further evaluation of the necessary meter configuration(s) and baseline methodologies needed to avoid double compensation. This recommendation applies to all DER whether or not it is facilitating demand reductions.
  However, the NYISO should evaluate if there is a legitimate means to compensate DER for ancillary services without compensating it twice for energy and capacity if the DER is also being compensated under the VDER Tariff.
- Use of control groups in a baseline methodology is not recommended at this time. While control groups have great appeal, and are being explored in the CAISO, it also requires a larger rollout of interval metering not yet in place in New York, but that rollout could accelerate with REV.
- With respect to the aggregation of baselines, the recommendation is for the NYISO to continue the practice of adding up the baselines from each site to get to the aggregate resource baseline to remain consistent with the highest 5 of 10 baseline methodology.

Capacity Market Baselines

- In the short term, the recommendation is for the NYISO to first consider treating demand response different from energy supplied from generation, similar to the firm service level concept. Alternatively, the NYISO should keep the existing SCR structure for demand response, including the use of historic performance measures to adjust the maximum reductions, in unforced capacity terms, that can be offered, with one change: the maximum reduction offered from demand response resources, even those using on-site generation to facilitate reductions, should be no more than the contribution to coincident peak load, a value that DNV KEMA showed was consistently less than that ACL value by 6-8%.
- In the short-term, dual participation for DER receiving compensation under the NYPSC VDER Tariff for capacity and the NYISO capacity market should not be permitted until there is further evaluation of the necessary meter configuration(s) and baseline methodologies needed to avoid double compensation.

Ancillary Service Markets

- Consider use of the energy market baseline along with a minimum consumption limit to define reserve capability in the Day-ahead Market. ISO-NE’s concept of having a minimum consumption limit would allow DER mixed with demand response to offer reserve further away from real-time and ensure consumption would not need to be curtailed more than desired.

- Keep the current Reserve and Regulation Service testing and pre-qualification requirements for DR and DER. The provision of regulation service is complicated and requires advanced metering, telemetry, and communication. In some scenarios, it may be unlikely that DER combined with a host load seeking to provide regulation service will be able to be controllable as to qualify for regulation service due to its intermittency, variability of the combined DER output and load consumption.
- Evaluate the possibility for dual participation between the VDER Tariff at retail and NYISO Ancillary Services Market participation. DER, to the extent it is eligible to receive compensation under the VDER Tariff, may also still participate in the NYISO ancillary service markets so long as there is no double compensation . The NYISO should further evaluate the necessary meter configuration(s) and performance measurements needed to avoid double compensation of energy or capacity. For example, if a DER is providing reserves and the DER is called upon to provide energy, there need to be provisions in place to ensure the DER is not paid twice for the energy if called upon.

Sampling Methods for Non-Interval Metered Customer Aggregations

- Adopt established methods and guidelines as a default sampling method/guideline for demand response that follows CAISO and PJM. This includes standards for default coefficient of variation and minimum sample sizes for coefficient of variation studies.
- Statistical sampling is not suitable for non-DR DER. Statistical sampling in ISO/RTO markets is primarily related to mass market loads, and where there is homogeneity among those sites. However, DERs will have differences over a number of dimensions including size, location, and weather.
- Streamline the approval process for statistically sampled aggregations. NYISO should predefine a common sampling methodology for participation of demand response in its markets, including guidelines for how proposals are to analyze homogeneity within the population and samples. Once the methodology has been approved by stakeholders, market participants should be able to apply those methodologies subject to NYISO oversight and approval.
- Statistical sampling for ancillary service provision is not appropriate for the NYISO. First, no ISO/RTO surveyed in the study allows for statistical sampling for participation in the market for regulation and frequency response. With respect to reserves, some sampling is permitted in PJM and CAISO, but the requirements are more stringent than sampling for energy or capacity aggregations. But NYISO is a small system relative to PJM, and any

sampling errors in the provision of reserves will have much larger impacts on the ability to arrest a frequency drop in NYISO than in a market the size of PJM.

1 Introduction and Background

In 2016 the NYISO undertook an initiative to fully integrate Distributed Energy Resources (DER) into the wholesale Energy, Ancillary Service, and Capacity Markets it administers. The NYISO's initiative seeks to capture the reliability benefit DER provide the bulk power system, as well as their economic value to wholesale markets. The NYISO's effort aligns with the New York State Public Service Commission's (NYPSC) *Reforming the Energy Vision* (REV) proceeding initiated in April 2014,[3] which hopes to create a market to increase distribution system deployment of DER to promote efficiency and reliability, to empower customers to better manage their energy bills, and to provide greater fuel diversity.[4]

This wholesale market DER integration effort also follows a September 2014 NYISO-commissioned report by DNV GL reviewing DER penetration and opportunities in New York.[5] The report investigated why customers adopt DER, engaged in a technical and market assessment of DER, reviewed rate incentives for DER, and discussed DER-appropriate measurement and verification, metering, and other business requirements. The report concludes that DER growth will continue as costs come down and technology improves, and that customers can benefit from DER, but retail rate design along with state and federal incentives may encourage greater DER penetration.[6]

This report focuses its analysis on three main areas of study related to measurement and verification of DER: metering institutions, baselining (energy and capacity), and statistical

[3] *See*, New York Public Service Commission (NYPSC), *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Case 14-M-0101, April 25, 2014. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9CF883CB-E8F1-4887-B218-99DC329DB311}, *See also*, New York Department of Public Service (NY DPS), Case 14-M-0101, *Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal* (Apr. 24, 2014), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5A9BDBBD-1EB7-43BE-B751-0C1DAB53F2AA} (*REV Staff Report and Proposal*).
[4] *REV Staff Report and Proposal* p. 6.
[5] DNV GL, *A Review of Distributed Energy Resources* (Sept. 2014), *available at* http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Other_Reports/Other_Reports/A_Review_of_Distributed_Energy_Resources_September_2014.pdf.
[6] *Id*. p. 2-7

sampling. As stated in the DNV GL study, the measurement and verification rules used for demand response provides a logical starting point for this evaluation. Moving forward, robust measurement and verification will be essential for wholesale market DER operations and market settlements. [7]

1.1 NYISO DER Roadmap and the Driver for this Study

In February 2017, the NYISO released its *DER Roadmap* outlining its proposed path forward for integrating DER into the NYISO-administered wholesale Energy, Capacity, and Ancillary Service Markets.[8] In the *DER Roadmap* NYISO expresses the view of DER as behind-the-meter resources, although small aggregations of Community Distributed Generation (CDG), may also be considered DER and some DER may be net-generators and others net-loads.[9] DER as a resource, or a set of resources, is typically located on an end-use customer's premises that can provide wholesale market services but are usually operated for the purpose of supplying the customer's electric load. DER can consist of demand response, generation, or storage on a stand-alone basis or various combinations such that they would be dispatchable by the NYISO.[10] The reason for integrating DER in the NYISO markets is to reflect the economic and reliability value they can bring to the NYISO system.[11]

This Meter Data Study report is part of the Meter Policies track in the DER Roadmap with this study being delivered as envisioned by the end of Q4 2017.[12] This study covers metering policies and requirements related to the following as outlined in the *DER Roadmap*:

- Metering for DER as may be required;
- Baselines for DER as required and modification to existing baselines if needed;

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[7] *Id*. p. 12-15.
[8] New York Independent System Operator (NYISO), *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets*, January 2017. Available at http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/DER_Roadmap/Distributed_Energy_Resources_Roadmap.pdf.
[9] *Id*. p. 5
[10] *Id*. These combinations could consist of demand response, demand response plus generation, demand response plus storage, demand response plus generation plus storage, generation alone, storage alone, or generation plus storage. *See also* p. 15
[11] *Id.* p. 4
[12] *Id*. Figure 5, p. 9.

- Potential for the sampling of a subset of DERs for establishing baselines and for market settlement in the energy, capacity and ancillary services markets;
- Meter data policies and the role of entities providing meter services;
- Interactions of baselines and DER aggregation; and
- Simultaneous participation in both retail and wholesale markets.

1.2 Retail Compensation and Metering Requirements for DER Come into Focus

Before focusing on the various measurement and verification approaches used in other competitive wholesale markets, it is important to identify the metering rules and policies used in New York State retail markets. In addition to the existing Meter Data Service Provider (MDSP) and Meter Service Provider (MSP) rules discussed in section 2.1 of this report, the New York State Department of Public Service (DPS) issued a new staff report and recommendations on the Value of Distributed Energy Resources (VDER) on October 27, 2016.[13] In that report, DPS staff recommended a tariff that would compensate DER for: 1) energy at the applicable wholesale Day-ahead LBMP; 2) capacity at the wholesale spot auction price for capacity at the DER's location; 3) environmental attributes at the higher of the price of Tier 1 Renewable Energy Certificate in New York or the Social Cost of Carbon; and 4) for the value for distribution system relief and demand reduction.[14]

DPS staff recommended that VDER tariff compensation be available to: 1) intermittent and non-dispatchable renewable technologies; 2) dispatchable technologies such as combined heat and power (CHP) (less than 10 kW), and technologies under 2 MW including farm waste and fuel cells; and 3) storage. DPS staff further recommended that participating DER use at least hourly interval metering to accurately account for DER performance and compensation under the VDER tariff.[15] DPS staff's report explicitly recommended excluding all dispatchable resources greater

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[13] NY DPS, Case 15-E-0751, *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding* October 27, 2016 *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={59B620E6-87C4-4C80-8BEC-E15BB6E0545E} .
[14] *Id*. p. 31-38.
[15] *Id*. p. 26.

than 2 MW, CHP larger than 10 kW, energy efficiency and demand response, and natural gas or diesel-fueled resources (except eligible fuel cells and CHP).

On March 9, 2017, the NYPSC approved the VDER tariff proposed by DPS staff including the recommended eligible technologies and the requirement for at least hourly interval metering of DER under the VDER Tariff.[16]

1.2.1 Study Strategy and Organization

This study takes the strategy of summarizing the key features being addressed by the study as enumerated above in the NYISO and ongoing events in three other ISO/RTO markets that have many similarities to the NYISO: PJM, ISO New England (ISO-NE), and the California ISO (CAISO). PJM and ISO-NE are neighboring markets with centralized capacity markets, a large penetration of demand response from which to draw lessons. The CAISO has a high penetration of DER already as well as demand response from which to draw lessons as well. The 2014 DNV GL report to the NYISO explicitly states that lessons for DER can be drawn from the existing rules and experience with demand response overall.[17]

The study is organized as follows. Section 2 covers the broad area of what are referred to as "metering institutions" which gets into the rules surrounding entities providing metering services. Section 3 covers energy market baselines. Section 4 covers capacity market baselines. Section 5 discusses DER participation in ancillary service markets. Section 6 discusses the potential for statistical sampling to allow mass market aggregation and participation in energy, capacity, or ancillary service markets.

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[16] *New York State Pub. Serv. Comm'n*, *In re* the Value of Distributed Energy Resources, Case 15-E-0751, *Order On Net Energy Metering Transition, Phase One Of Value Of Distributed Energy Resources, And Related Matters,* Case 15-R-0751 March 9, 2017. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5B69628E-2928-44A9-B83E-65CEA7326428}.
[17] DNV GL, *A Review of Distributed Energy Resources* (Sept. 2014), p. 1

2 Metering and Meter Data Institutions for Wholesale Market Participation

Metering and meter data institutions refer to the rules, procedures, and standards through which metering services are defined and implemented for wholesale market participation. In the context of an RTO/ISO market such as the NYISO, these rules, procedures, and standards can appear in the NYISO's Open Access Transmission Tariff or Market Administration and Control Area Services Tariff with additional details in NYISO operating manuals (*see., e.g.*, Revenue Metering Requirements Manual),[18] and can incorporate by reference existing standards and definitions as defined elsewhere (*see, e.g.*, Emergency Demand Response Program Manual)[19].

2.1 Current NYISO Metering Institutions

2.1.1 Service and Provider Definitions and Rules

The NYISO's tariffs and manuals do not provide explicit metering institutions for Demand Side Resources or DER, instead incorporating by reference two service categories, and by extension service providers, developed by the New York State Public Service Commission. The first service category consists of direct metering services that include installation and removal, maintenance, and testing of meters and related equipment. Meter Service Providers (MSPs) could be considered providers of these services.[20]

[18] NYISO, *Revenue Metering Requirements Manual*, Version 2.0, December 13, 2016. Available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Administrative/rev_mtr_req_mnl.pdf.

[19] NYISO, *NYISO Emergency Demand Response Program Manual*, Version 7.2, June 3, 2016. (NYISO EDRP Manual), Available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/edrp_mnl.pdf

[20] New York Independent System Operator (NYISO), *NYISO Emergency Demand Response Program Manual*, Version 7.2, June 3, 2016. (NYISO EDRP Manual), p. 1-2. Available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/edrp_mnl.pdf.

The second service category consists of meter data services which include meter reading, meter data translation, and customer association, validation, editing, and estimation. Meter Data Service Providers (MDSPs) could be considered providers of these services.[21]

New York State permits third parties, in addition to New York State utilities, to perform these services pursuant to its competitive metering rules for retail service. The current rules do not allow for Direct Customers[22] to self-supply MSP or MDSP services. The rules defining the roles and obligation of MSPs and MDSPs are set out in the *New York State Rules and Regulations (16 NYCRR Parts 13, 92, & 93), and the New York Practices and Procedures for the Provision of Electric Metering in a Competitive Environment* which are incorporated into incumbent utility tariffs.[23] The NYPSC approves MSPs and MDSPs and the list of currently approved MSPs and MDSPs is available on the NYPSC website.[24] The policy of competitive third party metering has been in place since 1999.

The NYISO has adopted and incorporated into its rules by reference the NYPSC-defined MSP and MDSP terms. Technical standards that are set forth in 16 NYCRR Part 13,[25] 92,[26] and 93,[27] which

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[21] *Id.*
[22] New York State Pub. Serv. Comm'n, *Uniform Business Practices, Case 98-M-1343, February 2015. Available at http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8dd2b96e91d7447e85257687006f3922/$FILE/UBP%20Manual%20Feb%202015%20Final.pdf*
An entity that purchases and schedules delivery of electricity or natural gas for its own consumption and not for resale. A customer with an aggregated minimum peak connected load of 1 MW to a designated zonal service point qualifies for direct purchase and scheduling of electricity provided the customer complies with NYISO requirements. A customer with annual usage of a minimum of 3,500 dekatherms of natural gas at a single service point qualifies for direct purchase and scheduling of natural gas.
[23]New York Department of Public Service (NY DPS), *New York Practices and Procedures for the Provision of Electric Metering in a Competitive Environment,* June 1, 2008 available at https://www.coned.com/_external/cerates/documents/elecPSC10/Addenda.pdf, last accessed November 22, 2017. The latest version of the *New York Practices and Procedures for the Provision of Electric Metering in a Competitive Environment* that could be located was dated June 1, 2008.
[24] NY DPS, *MSP/MDSP Eligible in NY Listing*, last updated November 25, 2015. Available at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/95DCF6AF23559B6985257687006F3A70?OpenDocument.
[25] *Compilation of Rules and Regulations of the State of New York, Chapter 16 Rules and Regulations of the Public Service Commission,* Part 13 (16NYCRR Part 13), available at http://www3.dps.ny.gov/N/nycrr16.nsf/Parts/5EEE0FB5A5517C9585256FC7004CFBA8
[26] *Compilation of Rules and Regulations of the State of New York, Chapter 16 Rules and Regulations of the Public Service Commission,* Part 92 (16NYCRR Part 92), available at http://www3.dps.ny.gov/N/nycrr16.nsf/Parts/BB13FCD2F1B1004F85256FC7004FA125.
[27] *Compilation of Rules and Regulations of the State of New York, Chapter 16 Rules and Regulations of the Public Service Commission,* Part 93 (16NYCRR Part 93), available at http://www3.dps.ny.gov/N/nycrr16.nsf/Parts/9FFF1763915BEF5C85256FC7004FAB53.

also references wider industry standards for metering from ANSI and NIST, apply to MSPs and MDSPs. Detailed procedures are available in the 16 NYCRR Part 92 Operating Manual dated March 14, 2003.[28]

2.2 PJM Metering Institutions

PJM has adopted similar metering technical standards used by NYISO for demand response which can include behind the meter generation.[29] PJM, like NYISO, allows for third parties, including Curtailment Service Providers (CSPs) to provide metering and data services as well as the incumbent utilities, but the CSP is the market participant responsible for submitting meter data and ensuring meter data accuracy.[30] Furthermore, PJM deems interval metering data must at minimum comply with the NAESB validating, editing and estimating (VEE) standards where applicable, except where it is also used for retail billing and settlement, to satisfy PJM metering requirements.[31]

Anecdotal evidence indicates that many aggregators like to set up their own metering and meter data and telemetry services that will go back to their operations centers to help ensure their sites are complying with their obligations to provide services.[32] Moreover, in the early years of demand response, there was anecdotal evidence that some incumbent utilities were slow to respond to metering requests so that third party aggregators would go ahead and install their own meters.[33]

PJM does not engage in the approval or pre-approval of third parties for metering, but rather places the responsibility upon the CSP for ensuring that all PJM enumerated metering standards are met, and at initial registration requires documentation regarding metering including technical specification, testing at the time of installation, and the name of the meter installer.[34] PJM also

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[28] NY DPS, *16 NYCRR Part 92 Operating Manual*, March 14, 2003, available at http://www.dps.ny.gov/Part92-Operating-Manual.pdf.
[29] PJM Interconnection, LLC, *PJM Manual 11: Energy & Ancillary Services Market Operations*, Revision: 92 Effective Date: November 1, 2017, (PJM Manual 11) Section 10.6, available at http://pjm.com/-/media/documents/manuals/m11.ashx. Curtailment Service Providers (CSPs) meters must meet all tariff defined metering requirements and ANSI c12.1 and c57.13 standards for metering. 16 NYCRR Part 92 only requires ANSI c12.1 standards for hourly interval metering be met.
[30] *Id.*
[31] *Id.*
[32] Author's experience and understanding as a member of PJM staff from 2008 to 2016.
[33] *Id.*
[34] PJM Manual 11, Section 10.6.

reserves the right to audit the meter and associated meter data. Failure by the CSP or the meter provider or meter data provider to submit to an audit will result in not being able to be the meter provider or meter data provider.[35]

In addition to auditing meters, or meter data, PJM allows for the incumbent distribution utilities to review demand response settlements within 10 days of submissions submitted by a CSP to check for anomalies against their own revenue quality meter data for the site.[36] If there are issues, PJM and the utility will work with the affected site to cure any problems with the meter data or the meter itself.[37] Furthermore, as an on-going check against potentially inaccurate meter data or strategic behavior, PJM will investigate any CSP that has more than 10 percent of its settlements disputed by the incumbent distribution utility and checks for days of consecutive settlements to preserve a stale baseline, settlements from variable demand when there was discernible price change, or settlements for load reductions based on normal operations.[38]

2.2.1 Analysis of PJM Metering Institutions

Unlike the NYISO, PJM only requires CSPs or their third-party contractors that provide meter and meter data services to meet the standards with the CSP being the party responsible to PJM. There is no pre-approval required for provision of these services. As a multi-state RTO, PJM cannot adopt any one state's metering standards, as the NYISO has done with the NY PSC standards indirectly by adopting the MSP and MDSP terms, but they do make the presumption that any retail interval metering infrastructure satisfies the PJM enumerated standards for metering. This eases the up-front burden on PJM staff.

PJM has a relatively small staff in Demand Response Operations so the ability to do any sort of pre-approval of CSPs or third parties for metering and meter data services is not practical. With the CSPs being the responsible party for satisfying the requirements for failure to meet standards, and the possibility they could lose the ability to provide these services themselves, which *de facto*

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[35] *Id.*
[36] PJM Manual 11, Sections 10.2 and 10.4
[37] *Id.*
[38] PJM Manual 11, Section 10.1. CSPs, if they submit settlements on a daily basis can preserve a baseline from non-event days more than one month in the past. CSPs would have an incentive to preserve a high baseline to show demand reductions when a more updated baseline would not be so high, absent daily settlements. These settlements would be for small dollar values at relatively low wholesale prices.

means they can longer participate in the PJM market, CSPs have strong incentives to follow the standards.

Moreover, with the ability of incumbent distribution utilities to check settlement data and identify metering discrepancies along with PJM checks on data and settlements, the task of monitoring meter data spread out over a wider pool of resources eases the burden on PJM staff to do all the monitoring themselves.

2.3 California ISO Metering Institutions

Much like in NYISO and in PJM, the California ISO (CAISO) allows for incumbent utilities and third parties to provide meter auditing, inspection, and certification services.[39] Only CAISO authorized companies can provide these services. Companies and inspectors can only become authorized through an application to the CAISO to become an authorized company or inspector, and must pass a CAISO administered exam.[40] Authorized auditors and inspectors cannot provide services if they have ever owned or leased the meter facilities, installed, designed, or programmed the meter, or hold a financial or ownership interest.[41] To facilitate the interaction between meter entities and authorized inspectors the CAISO has a separate metering department that administers the authorizations and exams, [42] and at the request of a Meter Entity, can also conduct inspections itself if the Meter Entity is unable to contract with an authorized inspector. [43]

However, CAISO has an additional role that does not exist in either NYISO or PJM and that is one of a Scheduling Coordinator. In the CAISO, the Scheduling Coordinator acts as the conduit to submit bids or offers into the CAISO market and is the entity responsible to be the supplier of

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[39] California Independent System Operator (CAISO), *Approved ISO Meter Inspection Companies*, available at https://www.caiso.com/Documents/ApprovedISOMeterInspectionCompanies.pdf. Within this document, the CAISO does not endorse any one particular company but only states these entities have passed the tests to provide inspection, auditing, and certification service in accordance with the CAISO tariff.

[40] CAISO, *CAISO Authorized Inspector Application and Renewal Procedure,* Version 1.3, July 28, 2016. Available at www.caiso.com/Documents/5720.pdf.

[41] CAISO, *Business Practice Manual for Metering,* Version 17, October 27, 2017, Section 3.2.3.3. Available at https://bpmcm.casio.com/Pages/BPMDetails,aspx?BPM=Metering.

[42] CAISO, *CAISO Authorized Inspector Application and Renewal Procedure,* Version 1.3, July 28, 2016. The exams are administered by the Energy Data Acquisition Specialists Team.

[43] CAISO, *Business Practice Manual for Metering,* Version 17, October 27, 2017, Section 3.2.3.3.

meter data directly to CAISO.[44] The Demand Response Provider can act as the Scheduling Coordinator or can contract with a third party to serve as the Scheduling Coordinator to submit meter data to the CAISO.[45]

CAISO metering technical standards are the same as in PJM requiring meters to meet the ANSI c12 and c57.13 standards. However, VEE procedures used in CAISO depend if the meter data from a resource is collected by the Scheduling Coordinator (*i.e.* SCME) or CAISO personnel (*i.e.* ISOME). For SCMEs, Scheduling Coordinators are deferred to obtain approval of its VEE procedures by the Local Regulatory Authority (LRA), such as the California Public Utilities Commission. For ISOMEs, CAISO has its own VEE procedures within the CAISO manuals.[46] CAISO appears to differ from other ISO/RTOs such as PJM and NYISO in that it has created its own comprehensive VEE procedures under the scenario where CAISO collects the meter data for ISOMEs, or Scheduling Coordinators that do not have LRA-specific VEE procedures that they are required to comply with.[47]

With respect to monitoring meter data accuracy and quality, CAISO requires all Scheduling Coordinators to provide complete and accurate data, and CAISO has the ability to suspend trading rights in the CAISO market as well as assessing penalties and sanctions, subject to FERC approval.[48] Furthermore, each Scheduling Coordinator must submit a Settlement Quality Meter Data (SQMD) Plan to the CAISO that includes testing, methods for collecting and validating meter data, and testing and auditing regimens. Each year the Scheduling Coordinator must attest that it is following its SQMD Plan.[49]

Finally, with the data systems that are set up in the CAISO systems for demand response, the CAISO has access to data submitted by Scheduling Coordinators on demand response that it can

[44] CAISO, *Demand Response User Guide*, Version 4.3, May 5, 2017 p. 13. Available at http://www.caiso.com/Documents/DemandResponseUserGuide.pdf.
[45] *Id.*
[46] CAISO, *Business Practice Manual for Metering*, Version 17, October 27, 2017, Section 3.2.3.1 and Attachment A.
[47] CAISO, *Business Practice Manual for Metering*, Version 17, October 27, 2017, Section 3.2.3.1 and Attachment D.
[48] CAISO, *Business Practice Manual for Metering*, Version 17, October 27, 2017, Section 4.2.
[49] CAISO, *Business Practice Manual for Metering*, Version 17, October 27, 2017, Section 6.1.

easily analyze for anomalies, though there is nothing in the CAISO documentation describing how they go about any such analysis.[50]

2.3.1 Analysis of CAISO Metering Institutions

The CAISO is taking an active role in monitoring, testing, and auditing metering and data providers in a much more direct, and "command and control" manner than PJM has taken through the spot checking of meter data and flagging settlements that indicate there are metering problems.

The documentation around metering certification, inspection, and auditing and ensuring that meter inspectors are free from conflicts is something that just does not exist in PJM or other markets with a large demand response presence. There is the lack of public documentation directly related to demand response to check for data anomalies that could indicate problems with metering or meter data submissions, but rather an emphasis on meter data plans submitted to CAISO, and annual attestations that the metering plans are being followed.

It may be enough of an incentive for Scheduling Coordinators and Meter Entities to ensure they follow all rules and standards to avoid the reputation of not be a reputable market participant.

2.4 ISO New England Metering Institutions and Upcoming Changes

ISO-NE permits third parties to provide meter and meter data services for demand response[51] as is the case in PJM, CAISO, and NYISO. Similar in concept to Scheduling Coordinators in CAISO, ISO-NE has what is known as a Demand Designated Entity (DDE) that acts as the conduit for transmitting 5-minute settlement and telemetry data to ISO-NE as well as receiving dispatch instructions from ISO-NE and sending these to demand response sites.[52] ISO-NE permits the Lead

[50] CAISO, *Demand Response User Guide*, Version 4.3, May 5, 2017 p. 113-147. Within the data systems, users can input metering data and can see the CBL and performance. It is not clear how the CAISO would screen the data for anomalies.
[51] In this case demand response refers to Real-time Demand Response and Real-time Emergency Generation in which demand is reducing load in response to energy market prices. It does not refer to On-peak Demand Resources or Seasonal Peak Demand Resources which are more like energy efficiency.
[52] ISO-NE, *ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR*, Revision: 6 Effective Date: June 1, 2014, Sections 1.1 and 9.3, available at

Market Participant to serve as its own DDE for metering and meter data services or to contract with a third party for those services. [53]

ISO-NE adheres to the ANSI metering standards similar to PJM and CAISO and requires 5-minute interval metering and corresponding data for all its demand response market activities.[54] With respect to ISO-NE checks on meter data accuracy through M&V audits, the current set of rules requires an annual independent, third party audit of metering and meter data practices.[55] The independent third-party audits can also be supplemented by ISO-NE audits of metering and data accuracy.[56] In the current rule set, there are no ISO-NE administered standards or qualifications for third party auditors of metering and data accuracy.

2.4.1 Pending Changes in ISO-NE Regarding Annual M&V Certification

Conversations with ISO-NE staff indicate the annual auditing and certification process was not working as intended. First, audits and certifications would come in late. Second, audits would come in indicating all was good with metering and data accuracy when there where, in fact, problems at various sites of which ISO-NE was already aware. Third, in moving toward full integration of demand response in the ISO-NE co-optimized energy and ancillary service dispatch, there is a greater need for accurate meter and telemetry data to be provided to the ISO/RTO than an annual audit and certification process would provide[57], and that measurement and verification would need to be done in almost real-time.

ISO-NE plans to replace the annual certification process with an ongoing process that requires market participants to immediately notify the ISO of any meter or telemetry accuracy issues,

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https://www.iso-ne.com/static-assets/documents/2017/02/mmvdr_measurement-and-verification-demand-reduction_rev6_20140601.pdf

[53] *Id.*

[54] ISO-NE, *ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR*, Revision: 6 Effective Date: June 1, 2014, Sections 9.3 and 10.2

[55] ISO-NE, *ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR*, Revision: 6 Effective Date: June 1, 2014, Section 14.

[56] *Id.*

[57] *See*, ISO New England and New England Power Pool, Docket No. ER17-2164-000, *Revisions to Implement Full Integration of Demand Response* (Jul. 27, 2017), Transmittal Letter at 41-43 and Prepared Testimony of Henry Y. Yoshimura on Behalf of ISO New England, Inc. (Yoshimura Testimony) at 21-23, *available at* https://www.iso-ne.com/static-assets/documents/2017/07/prd_implement_full_integration.pdf.

giving the primary responsibility for checking for meter data issues to the market participant.[58] However ISO-NE has indicated it will be conducting periodic analysis of the metering, telemetry or data communication systems and could seek to further automate the M&V of metering data they are receiving to automatically update energy market baselines for demand response.[59] Active demand response sites with bad data either reported by the market participant or discovered by ISO-NE may have these sites excluded from the aggregated demand resource and made unavailable to dispatch until the problems have been resolved.

2.4.2 Analysis of ISO-NE Metering Institutions

It is noteworthy that ISO-NE had independent auditing of metering and meter data and are moving away from it as M&V needs to be done more in real-time with the full integration of demand response into the energy market. Like PJM and CAISO, the documentation does specifically mention the ability to suspend market activity in the event of poor data reporting or metering problem which can be a powerful incentive.

If anything, ISO-NE seems to be moving in the direction of where PJM is today with monitoring meter data for anomalies, but going about this in a more automated fashion given the need for meter data fidelity in real-time. ISO-NE could look for issues such as zero values, large step changes, or repeated values in the meter data as an indication of a problem. ISO-NE could also compare meter data with information from sites such as retail bills, maximum loads, maximum behind-the-meter generation output and validate data with respect to these parameters. And this could be automated with the use of automatic updates to the baselines using meter data. And if problems are found with a demand response site, and they are not cleared, then those resources will not be available for dispatch. With the move toward the Pay-for-Performance framework,[60] the cost to demand response of being unavailable for dispatch when the system needs resources, and incurring large penalties, provides a strong incentive to ensure metering and meter data accuracy to ensure the site is available during a shortage event.[61]

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[58] ISO New England and New England Power Pool, Docket No. ER17-2164-000, *Revisions to Implement Full Integration of Demand Response* (Jul. 27, 2017), Transmittal Letter at 42-43 and Yoshimura Testimony at 21-23.
[59] *Id.*
[60] ISO-NE, *Market Rule 1*, Section III.13.7.2.7.1.2
[61] *Id.* The penalties can result in a loss of a substantial portion of the capacity market revenues.

2.5 Analysis of Meter Institutions

All the ISO/RTOs surveyed allow third party meter and meter data providers which provide flexibility to market participants, yet requires a well-defined set of rules and incentives to enforce metering and meter data standards as well as a monitoring framework. Each of the ISO/RTO markets takes a different approach.

One way to enforce the rules is through command and control mechanisms with a heavy ISO/RTO presence in approving third party providers of auditing services such as the CAISO. To the other extreme is PJM which expects CSPs, who are the ultimate responsible party, to ensure integrity of metering and meter data and if they do not follow the standards, they can lose the ability to participate in the market. ISO-NE is moving in this same direction where bad meter data can lead to demand resources being excluded from the market until the meter data is confirmed or the meter data problems are resolved. This is a move away from explicit annual auditing that ISO-NE has done previously.

With respect to technical standards, all the RTOs/ISOs surveyed rely on at minimum ANSI c12 standards, though each has its own set of requirements for interval metering ranging from hourly interval metering to 5-minute interval metering.

Monitoring meter data and checking for poor data or meters that are not functioning properly can be done in a variety of ways. PJM works with the incumbent distribution utility to check settlement data for demand response to ensure there are no issues. The upside to this approach is the reduction in staff time for PJM having “another set of eyes” examining the meter data and leveraging the knowledge and expertise of the distribution utility. The downside is that it is not clear how carefully the distribution utility will examine the meter data, or whether the distribution utility has the time to examine the submitted settlement meter data.

In contrast, ISO-NE is moving toward a more automated system to check for bad meter data. The upside to this is that once in place, it streamlines the monitoring process and makes it easier to identify questionable meter data and possible metering problems and does not rely on any other parties for assistance. The one drawback to this is that the IT infrastructure to set up such an automated monitoring regime could be time consuming and costly.

Finally, the route the CAISO has taken is more administrative. This requires dedicated staff to approve third party inspectors and auditors for metering, but it does send a strong signal to market participants that they are being monitored. Yet, even with such an administrative construct, there still needs to be a way to check the meter data for anomalies that are not detected in audits and inspections. The CAISO does receive this data, but from the manuals it is not clear how this is used for monitoring purposes.

2.6 Recommendations on Metering Institutions

2.6.1 Continue to Allow Third Party Entities to Provide Metering Services for Wholesale DR and DER Participation

This will simply continue what has already been permitted by the NYISO and allow DR and DER providers to self-supply these services for NYISO market participation. Continuing with allowing third party provision metering services provides DER and DR the ability to exploit any possible cost savings they may find outside of going through the incumbent distribution company and economies of scope in providing their own telemetering of data from sites to their operations centers to monitor performance of their contracted DER and DR sites, which can only help in providing telemetry back to the NYISO.

This recommendation does entail more responsibility for NYISO staff. NYISO will need to incorporate standards required of providers of metering services directly into the Tariff and Manuals, and will require some additional changes and development of incentives to ensure market participants and third parties taking on responsibility for metering functions adhere to the standards directly incorporated by the NYISO. The new metering service rules incorporated into the Tariff and Manuals could be based on existing metering standards (either from another ISO/RTO or from the NYSPC), or the NYISO could develop their own rules and standards. In either case, the NYISO should remove references to NYPSC rules to avoid confusion for what is required at the retail level with what is required at the wholesale level. The NYISO should further evaluate the expected NYISO development and administrative effort, and associated cost, to facilitate third party providers of metering services for NYISO market participation and work with its stakeholders to decide if this provision has a net benefit to its market participants.

Overall, continuing to permit third party metering services remains preferable to reverting back to the incumbent distribution utilities taking on the metering functions alone that existed prior to the opening of NYISO wholesale markets. From a NYISO staffing and effort perspective, reverting back to the incumbent utilities for metering functions seems attractive as it leverages experience and expertise already available with the utilities. Finally, such a policy would squarely place the incumbent utilities in the role of gatekeepers to the NYISO wholesale market, and decrease flexibility and the ability for DR and DER to take advantage of economies of scope to manage their own resources using the same metering and meter data infrastructure used for market participation.

2.6.2 Short-term M&V and Monitoring: Examine the Possibility of Working with Incumbent Utilities

Under this recommendation, most DR and DER will still have at minimum a revenue quality meter for the purposes of retail billing to which the incumbent distribution utilities will have access that may also be used for NYISO market participation, or a second meter that is used only for NYISO market participation. The incumbent distribution companies can provide data and information to the NYISO on metering or meter data issues they are seeing from DR and DER in much the same way PJM works with incumbent distribution utilities. However as mentioned in Section 2.5, the effectiveness of this approach will largely depend on the time and resourcing that the incumbent distribution utilities can commit to support this coordinated meter data review with the NYISO. The NYISO and the incumbent distribution utilities should explore the benefit of this approach over others such as where the incumbent distribution utilities are fully responsible for meter data services. In the short-term this would place minimal additional requirements on the NYISO staff and leverages the work the distribution utilities may already be providing to support REV.

2.6.3 Long-term M&V and Monitoring: Develop an Automated Monitoring Tool and Protocols

This will place a greater burden on NYISO staff up front to develop the IT infrastructure and protocols for monitoring data, but once in place would reduce the needed staff time to engage in effective monitoring and M&V of metering and meter data. This recommendation follows the path ISO-NE has taken to monitoring for data anomalies and bad metering or meter data. With this long-term solution, there may be a smaller role, for the incumbent distribution utilities in the monitoring and M&V function for wholesale market participation in the future.

2.6.4 Use Incentives Rather than Administrative Mechanisms to Enforce Metering and Meter Data Standards

The use of incentives such as penalties and the inability to participate in the NYISO market in the event there are ongoing problems with metering and meter data can enforce standards while minimizing the amount of NYISO staff time devoted to enforcement and administration of standards, however this approach could also increase NYISO staff time devoted to administering and reviewing penalties. This is the path PJM has used and it is the path that ISO-NE is taking going forward. In the case of ISO-NE, the use of administrative rules is no longer appropriate as they integrate demand response more fully into the energy and ancillary service markets with the need for immediate identification of meter data problems, and they have moved toward the threat of not permitting market participation unless any identified metering and meter data problems have been solved.

This recommendation is not to say that the NYISO should not have the power to audit third party entities providing metering services for compliance with standards, the NYISO should have this ability, but this should not be the primary tool to enforce standards as it can become costly. This is especially true as the NYISO more fully integrates DER into its markets in much the same way ISO-NE has done with demand response in its markets.

To opt for a more administrative construct, as exists in the CAISO market, would require additional staff and infrastructure to carry out than an incentive construct. Pre-approving independent third-party auditors and inspectors requires developing and continually managing a qualification program for these service providers that has not yet been developed in the NYISO context. Add to this, the potential for the NYISO to certify and approve third party entities to provide metering services and the cost in additional time and staff could become large and allocated to its market participants.

Table 1 below compares the recommendations to the NYISO regarding metering institutions in this Section 2.6 with other approaches toward meter and meter data institutions of other ISO/RTOs studied.

Table 1: Summary of Study Recommendations vs. other ISO/RTO Approaches for Metering Institutions

	PJM	ISO-NE	CAISO
Allow Third Party Meter Service Providers	**Yes, including self-certify**	**Yes, including self-certify**	**Yes**
M&V Monitoring Strategy	**Manual periodic checks by RTO with utility support**	**Automated periodic checks by ISO**	**Not Available**
Penalties for Non-Compliance	**Disqualification of CSP to provide meter services**	**Removal of resource from market**	**Penalties and sanctions by approval of FERC**
Administrative Mechanisms to Monitor Compliance	**Subject to RTO audits**	**Annual M&V audit by independent auditor in addition to being subject to ISO audits** **Annual M&V audits to be removed as a requirement**	**Authorization and training program administered by ISO for third party companies** **Bi-annual self-audit attestation of compliance by Scheduling Coordinator[62]**
Resourcing Level of ISO/RTO to Develop M&V Approach	**Low**	**High**	**Moderate**
Resourcing Level of ISO/RTO for Continuous Administration of M&V Approach	**Low**	**Moderate**	**High**

[62] CAISO, *Business Practice Manual for Metering*, Version 17, October 27, 2017, Section 6.4.2

3 Energy Market Baselines

The purpose of a customer baseline load (CBL) is to have a measure of the counter-factual consumption of a customer if it did not engage in a load reduction activity for demand response in the energy market. The use of CBLs is possible with DER that is associated with facilitating demand reductions, and in such cases DER may also be metered separately to assess its performance alone. There is no “economic theory” of how to determine baselines to define the counter-factual consumption absent taking a market position for consumption by purchasing energy in a commodity market context.

A good guide for determining the energy market baseline is that it should match the actual load, or net load if there is DER in the form of generation or storage behind the same meter as a load facility and it is not separately metered, as closely as possible which can be determined through empirical analysis. Intuitively, CBLs could also be adjusted close to real-time for major drivers of load such as temperature differentials.

The rest of this section is organized as follows. First, a discussion of what a CBL looks like in a commodity market context where a load consuming power takes a market position (agrees to a purchase of energy) and then has the possibility of selling that energy back to the system at the going market price. This is provided from the perspective of large, regulated utility customers and then within the broader ISO/RTO market context. Next a more general discussion of CBLs is provided in the context of demand response participating in wholesale power markets where customers do not have direct access to wholesale power markets that is then followed by a more specific discussion of CBLs in the context of the NYISO, and other ISO/RTO markets.

3.1 Energy Market Baselines in a Commodity Market Context

In most commodity markets, there must be ownership control of the commodity being sold or the ownership of the means of production for that commodity. In an efficient market with demand response and DER helping to serve the load behind the meter, the load would buy its position regarding how much it thinks it may consume (including decisions on DER output) and then sell back into the spot market what it does not consume at the associated spot market price. This is a tariff option for large commercial and industrial customers being served by operating companies of the Southern Company, such as Georgia Power.[63]

Under these tariffs the utility and customer agree upon a customer baseline load (CBL) for which the customer pays a fixed price, and then deviations from the CBL are paid for at the agreed upon "spot price" which could either be the day-ahead or real-time price as determined by the utility.[64] In this way the customer is taking a consumption position (*i.e.* CBL) at an agreed price. If the customer consumes less than the CBL, it gets paid the "spot price" for selling back what it has already purchased. If the customer consumes more than the CBL, it pays the "spot price".[65] An example of this is shown in Figure 1 below with the CBL (in blue) with a reduction from the CBL (in red).

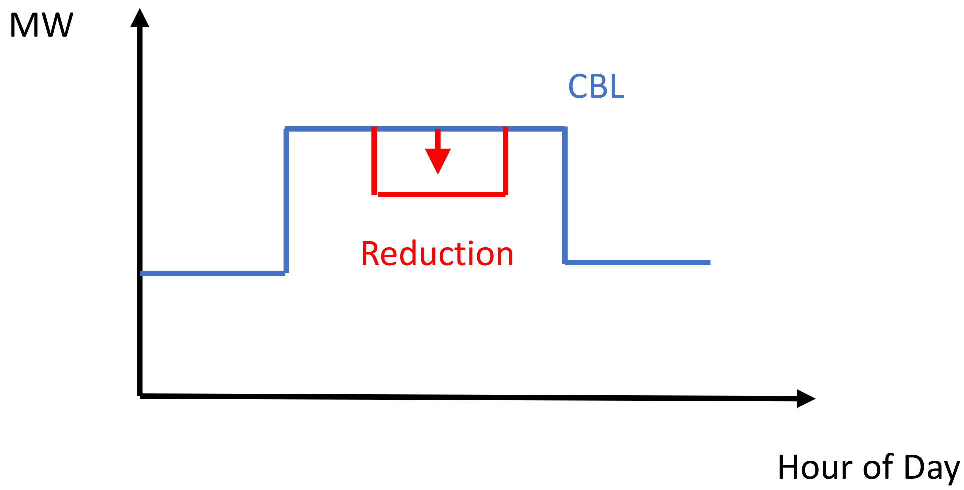
If DER were embedded into the customer load site, running DER to reduce load is simply a comparison of cost to run the DER versus the cost of buying energy at spot market prices.

[63] For example, see the Georgia Power home page for what they describe as "marginally priced rates" at https://www.georgiapower.com/business/prices-rates/business-rates/marginally-priced.cshtml.

[64] For example, see the Georgia Power *Real-Time Pricing - Day-ahead Schedule: RTP-DA-5*, available at https://www.georgiapower.com/docs/rates-schedules/marginally-priced/6.20_RTP-DA.pdf. "The CBL is initially developed using one complete calendar year of either customer-specific hourly firm load data or monthly billing determinant data that represents the electricity consumption pattern and level agreed to by the customer and Georgia Power. This CBL represents the customer's operation for billing under its conventional tariff. Changes in consumption, measured from the CBL, are billed at RTP-DA prices."

[65] Under the Georgia Power tariffs, customers have options to use the "spot price" as determined Day-ahead, or the spot price as determined an hour ahead. See Georgia Power *Real-Time Pricing - Day-ahead Schedule: RTP-DA-5* for the language on Day-ahead pricing: "Hourly prices are determined each day based on projections of the hourly running cost of incremental generation (including approved environmental costs), provisions for losses, projections of hourly transmission costs and reliability capacity costs for each day (when applicable), and a 3 mill/kWh recovery factor. The amount of fuel charges from hourly incremental kWh usage are applied to the recovery of fuel cost at the hourly average marginal fuel cost for the applicable hour." For hour-ahead pricing language see Georgia Power *Real-Time Pricing - Day-ahead Schedule: RTP-HA-5*, available at https://www.georgiapower.com/docs/rates-schedules/marginally-priced/6.30_RTP-HA.pdf. "Customers are notified each day of forecasted electricity prices for each hour of the following day, then prices are updated each hour, sixty minutes before becoming effective. Prices are based on projections of the hourly running cost of incremental generation (including approved environmental costs), provisions for losses, projections of hourly transmission costs and reliability capacity costs for each day (when applicable), and a 2 mill/kWh recovery factor. The amount of fuel charges from hourly incremental kWh usage are applied to the recovery of fuel cost at the hourly average marginal fuel cost for the applicable hour".

Figure 1: Simple Example of a CBL with a Reduction



3.2 Commodity Market Context CBL is embedded in the ISO/RTO Market Two-Settlement Systems

The commodity market concept described above is already embedded in the structure of settlements between the Day-ahead and Real-time Energy Markets that are in operation across ISO/RTO markets in the United States. A load directly participating in the wholesale market can take a financially binding Day-ahead position in each hour by committing to buy a certain quantity of energy at the Day-ahead price applicable to that hour. This is the analogous to the CBL quantity paid for at an agreed price in the commodity market context described above. Then if the load directly participating in the wholesale market consumes less in real-time than they purchased day-ahead, they will be paid the real-time price for the quantity of energy sold back. If the load consumes more than the amount purchased day-ahead, it will pay the real-time price for consumption above its day-ahead purchase. This is analogous to the differential between the CBL and real-time consumption settled at the "spot price" as described above and shown in Figure 1.

3.3 CBL for Load Not Participating Directly in Wholesale Markets

Most loads providing demand response (DR) within the wholesale market context do not have the ability to take a forward position for energy in the Day-ahead Energy Market because they cannot participate directly in the wholesale market. Additionally, loads may not have the option to take a forward position similar to those described above for Georgia Power at the retail level because the retail service provider or load serving entity does not offer similar tariff options described above where the retailer or load serving entity can act as an agent for the load settling differences between contracted load and actual load at the wholesale market price. Finally, some loads are too small and do not have the means to facilitate taking such a position because transactions costs would be too large.

As an alternative, a CBL is measured based on recent historic consumption as a proxy for what the customer would have consumed absent any action to reduce consumption. But because it is difficult to know what any specific customer site is intentionally doing to reduce consumption the only indication wholesale markets have for this action is if the customer site has signaled to the wholesale market through submission of a settlement request for payment for demand reductions.[66] CBLs can be used to facilitate settlements of energy or certain ancillary services, such as reserves, in either the day-ahead energy market or the real-time energy market. And the discussion in this section is relevant to both day-ahead and real-time participation.

The goal of a CBL is to as closely as possible match the CBL with the actual load and minimize the error between the CBL and the actual load observed. Consequently, to get an accurate CBL it is essential to omit any days or time periods in which a demand reduction has been submitted for settlement to the wholesale market so as not to bias downward the CBL for future settlements as any CBL using days or periods in which demand reduction have actively taken place is no longer an unbiased measure of what consumption would be absent the demand reduction.

The next several subsections describe the considerations and components of constructing a CBL on a more generic basis before getting into the specific comparison and considerations for CBL across other ISO/RTOs.

3.3.1 Drivers of Energy Consumption and Consideration for CBL Determination

Generally, drivers of energy consumption include the following:

[66] In the wholesale market context, providers of demand response do provide plans to the ISO/RTO markets that describe how they will implement load reductions whether it is through as direct reduction in load (and the means by which that is done) or though on-site generation/DER and the specifications regarding the on-site generation/DER such as MW capability.

1. Day of the week. This could be a business day in which demand and energy consumption is generally higher than on weekends or holidays. A distinction between non-holiday weekdays and weekends and holidays is warranted as consumption and peak demands are typically higher on weekdays (workdays) than they are on weekends and holidays for commercial and industrial (C&I) loads, though the opposite may be the case for residential loads.
2. Time of day. Consumption is usually higher toward late afternoon or early morning (depending on season) and lower overnight. CBLs measured on at least an hourly basis will cover the variation in load for time of day, and CBLs can be measured even on a 5-minute interval basis as necessary for providing ancillary services such as reserves.
3. Season. Summer loads can be driven by air conditioning load and winter loads by heating needs such as power needed for fans used for forced air heating or resistance space heating needs. Peaks can happen early in the morning or early evening in the winter, while it happens in the late afternoon in the summer. Within a short window of history, the seasons do not change. But temperature variation within seasons will drive changes in energy consumption, and adjustment can be made to the CBL for temperature variations.
4. Temperature variations. The need for energy to serve air conditioning or heating load levels in any season will be driven by extreme temperatures or temperature variation that is present on a day-to-day basis.
5. Macroeconomic conditions. Macroeconomic conditions will drive overall activity and consumption trends and will not change on a day-to-day, week-to-week, or month-to month basis so adjustments to economic conditions overall are not necessary.

3.3.2 CBL Weather Adjustments

Given daily temperature variations, and the fact that changes in loads are weather driven, it makes sense to allow for weather adjustments. Such adjustments can be simple or complex. A simple method is to compare the consumption on the day a demand reduction settlement is submitted (known also as an event day) relative to the CBL, but in the period prior to the settlement period. This is sometimes called a same-day weather adjustment.[67] This is a revealed energy consumption level given the temperature differential from the as measured CBL. The adjustment measure should

[67] See NYISO, *Emergency Demand Response Program Manual,* Section 5.2.2, III, p. 5-8 to 5-9 as an example.

be close to the timing of the submitted settlement period for demand reductions, but also not so close as to allow customer sites to "strategically increase" consumption just before the event to increase their measured demand reduction. Such a method would also capture the effects of humidity on energy consumption as well. For summer reductions, higher humidity tends to be associated with higher air conditioning load. In contrast, the winter heating load tends to be lower with higher humidity since the humidity helps retain heat better than drier air.

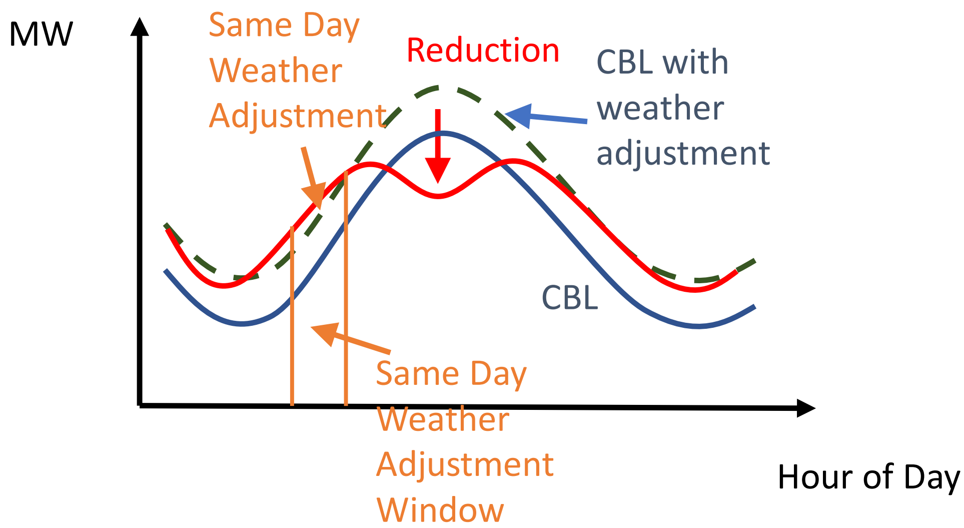
A more complex method is to analyze a large sample of temperature and consumption data while adjusting for time of day, season, and economic conditions to isolate the effect of temperature variation (or even humidity variation or the combination of temperature and humidity) on energy consumption levels through econometric regression techniques.[68] Such a method could be useful in making adjustments automatically without measuring load in a window prior to the reduction settlement period. In this method, the ability to strategically increase consumption prior to a reduction is not possible as the adjustment is formulaic based on the regression analysis. Yet such methods are more difficult to implement due to their complexity and possible issues with data quality.

Finally, one last option for implementing a weather adjustment is to use a control group of customer sites that are not submitting reduction settlements but for which customer baselines can be determined and for which there is no strategic incentive to increase consumption since the control group is not submitting settlements for demand reductions.[69]

Figure 2 shows how a weather adjustment could be implemented. The original CBL is shown in blue in Figure 2. The weather adjusted CBL is shown as the green dotted line. The weather adjustment window is shown in orange and the same-day weather adjustment is the difference between the green dashed load profile and the solid blue profile within the orange adjustment window. The results in a higher CBL for the load event that the original CBL.

[68] PJM allows for such weather adjustments. See *PJM Manual 11*, Section 10.4.2, p.140-142.
[69] This has been proposed for the CAISO. See Nexant, *California ISO Baseline Accuracy Work Group Proposal*, April 4, 2017, available at https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupProposal-Nexant.pdf.

Figure 2: Same Day Weather Adjustment Example



3.3.3 Number of Historic Days to Average

How many days to average to get the best CBL representation is at its foundation an empirical question. Ideally, the sample of days should be large enough to smooth out variations yet also get a sense of energy demand absent demand response given the day of the week and season of the year. Yet the sample must also be sufficient close in time to be representative of energy consumption by which demand reductions are measured. Essentially there is a trade-off between getting a large enough sample size, and how far back in time to go to get the sample.

The general ISO/RTO approach has been to use an average over a window of at least 5 more recent non-event days out of the past 10 non-event days, such as in the NYISO, PJM and proposed for some customer classes in the CAISO,[70] and as many as the past 10 non-event days for normal

[70] For NYISO, *see* NYISO, *Emergency Demand Response Program Manual*, Section 5.2.2. For PJM, *see* PJM Interconnection, *PJM Manual 11*, Section 10.4.2. For CAISO, *see* Nexant, *California ISO Baseline Accuracy Work Group Proposal*, April 4, 2017.

weekdays as is used currently in ISO-NE and CAISO.[71] A subset of the highest non-event days has been used and is still being used or proposed in the ISO/RTO context.[72]

One possible issue that arises with the use of a subset of the highest non-event days is that it biases the CBL upward from taking the average of all non-event days in the window. But this bias is likely overcome by the use of a weather adjustment as discussed above. If the CBL is biased high, and temperatures are high, the weather adjustment may not be as large as would have otherwise been the case. And if temperatures are cooler (assuming a summer period), then the weather adjustment may be larger than otherwise the case.

3.3.4 Look-Back Period

A CBL that is representative of consumption absent any demand reductions avoids using any days in which a demand reduction has been submitted for settlement (aka an event day). It is possible a customer site could submit settlements for reduction over a period of many days during a heat wave or severe cold spell. The question is how far back to look for "non-event" days by which to calculate the baseline. The look back period should be long enough to be able to capture a sufficient number of "non-event" days whereby a CBL can be established, but also short enough to not be in a different season of the year where consumption patterns can change.[73]

3.3.5 Use of Control Groups for Demand Reductions

Control groups, whether they are randomized control groups chosen among possible sites for demand reductions, or matched control groups where the control group has the same characteristics as the market participant group. Control groups can be an alternative to using historic consumption data for determining a CBL by comparing the consumption patterns of a control group that does not engage in any demand response activity to a like group that has engaged in demand response.

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[71] ISO-NE, *ISO New England Market Rule 1*, Section III 8A, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_1_12.pdf. CAISO, *Demand Response User Guide*, Version 4.3, May 5, 2017, p. 160-163.

[72] NYISO, *Emergency Demand Response Program Manual*, Section 5.2.2 currently uses this method, and Nexant, *California ISO Baseline Accuracy Work Group Proposal*, April 4, 2017 has proposed this for residential customers classes.

[73] In general, the look-back periods have ranged from 30-45 days across the ISO/RTO markets surveyed in this study.

In its study for the California ISO Baseline Accuracy Working Group, Nexant recommends three principles for validation of the control group:[74]

1. Little of no bias. The bias in load reduction measurement, if any, should be small enough to be corrected through same-day weather adjustments. The statistical test for bias is an ordinary least-squares regression of the market participating loads against the control group loads without using an intercept term. If the value of the estimated coefficient is between 0.95 and 1.05 Nexant would conclude there is no bias.
2. 90/10 precision. That is the error in load reduction measurement should be less than 10 percent with a 90 percent confidence. This can be examined by computing the normalized root mean squared error.
3. Minimum sample size of 150.

3.3.6 Metering or Sub-metering of On-site Generation or DER

Often customer sites that engage in demand reductions utilize on-site generation or storage to facilitate demand reductions and potentially even net injections into the grid. In many cases the on-site generation is used either on a regular basis to help serve some on-site electric load or is serving on-site steam load that is used by an industrial process.

There are at least 3 different meter configurations that could support on-site generation or DR as identified by the NYISO as shown in Figure 3.[75] The first is a single meter at the facility/site fence-line with both the load and generation behind the facility and shown by the middle configuration in Figure 3. In such a configuration, any CBL that is determined would be accounting for both the load and generation as a single combination.

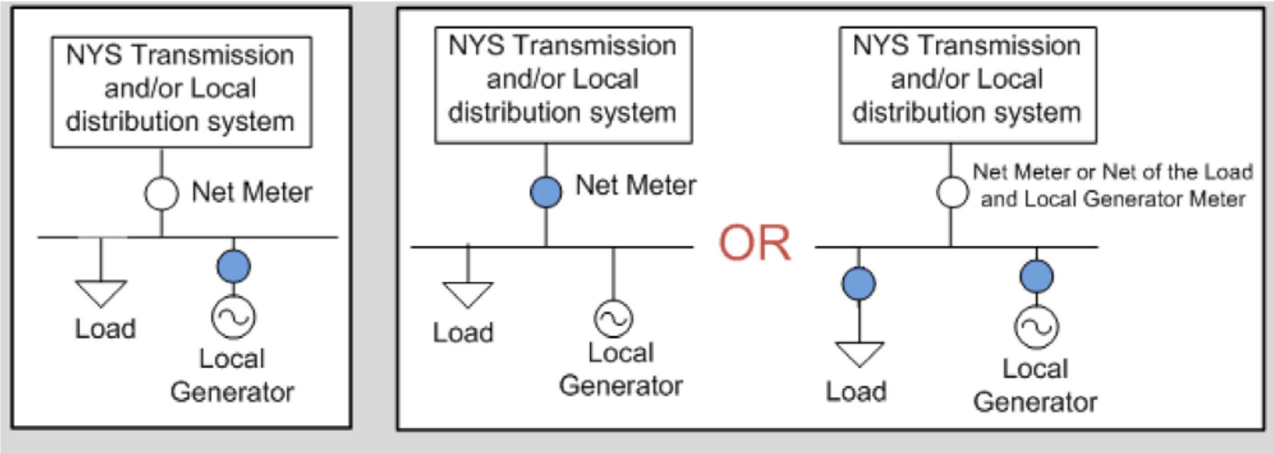
The second configuration could be one in which the total facility load is metered as well as the output from the on-site generator or DER is also directly metered as shown in the far-left configuration of Figure 3. In this configuration, the generation output can be baselined and measured separately from the net facility load which is also has a CBL determination.[76] This

[74] Nexant, *California ISO Baseline Accuracy Work Group Proposal*, April 4, 2017, Section 4, p. 12-13.
[75] Figure taken from NYISO, *Emergency Demand Response Program Manual*, Figure 5-1.
[76] CAISO has outlined explicit rules for baselining on-site generation. *See* CAISO, *Demand Response User Guide*, Version 4.3, May 5, 2017, p. 164-167.

configuration can measure reductions in net facility load due to either on-site generation or DER as well as a process to reduce the gross facility or site load before it is measured at the meter at the site/facility fence-line.

The last metering configuration can meter separately the facility/site gross load, on-site generation/DER output, and a meter at the facility fence-line measuring net load as shown in the far-right meter configuration in Figure 3. The facility load can be metered independently of generator output and generator output is metered independently as well. In this way demand reductions can be attributed to either actions to reduce load or increases in generator output.

Figure 3: Meter Configurations with On-site Generation/DER



Whether direct metering or sub-metering of on-site generation/DER should be required is a matter of debate and circumstances. There are a few things that can prevent a site from being baselined in specific configurations such as (i) the use of unapproved meters; (ii) lack of process to certify meter data from submeters; (iii) meter cost; and (iv) differences in retail and wholesale metering requirements.

There is nothing to prevent a site or facility baseline being determined in any of the above three configurations. The issue is the predictability of the use of the on-site generation/DER.

If the purpose of generation is to only reduce facility load in response to price or as an emergency generator, such as on the far left of Figure 3, then metering of the on-site generation/DER is necessary as this is the measure of the demand reduction.

If the net output is relatively constant to support on-site processes, or at the other extreme if the generation/DER is used only infrequently to support reductions in the total facility metering, then most baselines methods discussed below do not require explicit metering of on-site generation/ DER, but it is helpful.[77]

But if the on-site generator, or even storage DER, injects power at times to support an increase in facility load, but at other times the increase in facility load (or storage charging) is met through increased consumption without any discernible pattern, the net load appears to be highly variable and separate metering of the on-site generator may be required to better measure a CBL for the load.[78]

Historically, this has not been big issue, but as more DER in the form of storage, which looks like load at times, and generation at other times, or DER coming from intermittent resources becomes more integrated, requirements for metering of on-site generation/DER may become necessary.

3.4 Current and Prospective ISO/RTO Market Energy CBLs

Table 2 below provides a summary of a sample of current and prospective ISO/RTO CBL methodologies.[79] For each ISO/RTO CBL described there are baselines for weekdays, weekends and holidays, the defined look-back window, and weather adjustment characteristics.

[77] For example, PJM in its documentation explicitly calls out whether on-site generation is used to support facility load on a normal operations basis, or whether it is only supporting demand reductions. PJM does not explicitly call for a "baseline" for on-site generation, but allows for a CSP to provide such information to support when generation helped reduce facility load. PJM also requires as part of the registration, information regarding on-site generation. *See PJM Manual 11,* Section 10.4.1 and Section 10.2.

[78] CAISO accounts for storage devices that are charging and discharging as a generator that can support demand response. In coming up with the generator baseline for storage, the CAISO normalizers the generator output to zero. If the storage device, in combination with load net injects to the system, the facility load is normalized to zero for the purpose of settling demand response. *See* CAISO, *Demand Response User Guide*, Version 4.3, May 5, 2017, p. 168-169.

[79] Citations to each CBL method are provided in the subsections that follow.

Table 2 – Summary of ISO/RTO Current and Prospective CBL Methodologies

	Weekday Baseline	Weekday Lookback	Weekend & Holiday Baseline	Weekend Lookback	Weather Adjustment	Weather Adjustment Bandwidth
NYISO	Average of highest 5 of last 10 non-event days	30 days	Highest 2 of last 3 non-event days	30 days	2 hour window starting 4 hours prior the event	+/- 20%
PJM (tariff)	Average of the last 5 non-event days	45 days	Average of last 3 non-event days	45 days	Regression defined permitted	None defined
ISO-NE (current)	Average of the last 10 non-event days for each 5 minute interval	30 days	None defined. All days treated the same	Not applicable	2 hour window 2.5 hours prior to the start of the event	Adjusted CBL no greater than max facility load
ISO-NE (6/1/18)	Average of the last 10 non-event days for each 5 minute interval	30 days	Saturday, Sundays, and Holidays treated individually. Average of last 5 non-event days	42 days	25 minutes prior to the start of the event to 10 minutes before the event.	Adjusted CBL no greater than max facility load
CAISO (current)	Average of last 10 non-event days	45 days	Average of last 4 non-event days	45 days	3 hour window 4 hours prior to the event	+/- 20%
CAISO (proposed C&I)	Average of last 10 non-event days	Not defined		Not defined	2 hour window starting 4 hours before event	+/- 20%
CAISO (proposed residential)	Average of highest 5 of last 10 non-event days	Not defined	Average of highest 3 of last 5 non-event days	Not defined	2 hour window starting 4 hours before event	+/- 40%

3.4.1 NYISO[80]

The current NYISO Energy Market CBL for weekdays is defined as the average of the highest 5 of the last 10 non-event days. For weekend and holidays, the CBL is the average of the highest 2 out of the last 3 non-event days.

The NYISO CBL provides for weather adjustments using 2-hour window starting 4 hours prior to the event. The maximum adjustment can be no more than plus or minus 20 percent.

The NYISO does not require metering of on-site generation, but does require a customer site to provide an indication of how reductions could be made by declaring a type of demand response such as Type G for reductions from generation only, or Type B for reductions that could come from reduced consumption or increase in on-site generation.

3.4.1.1 2014 DNV KEMA Baseline Study

In 2014 DNV KEMA presented the NYISO with a CBL study of various baseline options as a comparison to the current Average Coincident Load (ACL) baseline used for Special Case Resources in the Capacity Market.[81] In this study they tested multiple CBL methodologies with differing weather adjustments. KEMA concluded that one of the top performing baselines was the current NYISO "5 of 10" baseline with a multiplicative adjustment factor for weather (in the 90th percentile).[82] It also noted the use of the average of the past 10 non-event days similar to those used in the CAISO and now ISO-NE (and discussed below) were also high performers, and even slightly better than the current NYISO CBL.

DNV KEMA also noted that much of the performance issues with different baselines tested centered on highly variable loads. In fact, DNV KEMA concludes that with respect to highly variable loads, "[t]he analysis concludes that a baseline approach to measuring load reduction may not be applicable for resources with certain kinds of variable load. When a resource's load is uncorrelated to an identifiable previous load pattern, there is no generalized baseline methodology

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[80] NYISO, *Emergency Demand Response Program Manual*, Section 5.2

[81] DNV-KEMA, Inc., *NYISO SCR Baseline Study*, March 2014. Available at http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Demand_Response/Special_Case_Resource_ICAP_Program/NYISO%202013%20SCR%20Baseline%20Study%20Report-final.pdf

[82] *Id*. p. 6

that can produce an effective baseline. The aggregate analysis results indicate that an upper limit on variability should be considered."[83]

3.4.2 PJM[84]

The underlying requirement for a CBL to be used by a load in PJM is that CBL must have a relative root mean square error (RRMSE) of less than 20% to ensure the accuracy of the CBL with actual loads.[85] PJM is the only ISO/RTO surveyed that has this accuracy requirement explicitly stated. PJM has a single default CBL methodology in the tariff which is the one presented in Table 1 and 8 other possible choices that are defined in the PJM Manuals that have been designed to accommodate variable loads that have an RRMSE of more than 20% under the default tariff CBL.

The PJM standard tariff defined CBL for weekdays uses the average of the last 5 non-event days in the past 45 days for weekdays. For weekends and holidays it is the average of last 3 non-event days out of 45.

With respect to weather sensitive adjustments, the use of a 3-hour window, 4 hours prior to the event provides the adjustment.[86] PJM also permits regression defined weather sensitive adjustments for use with some methods. There is no cap on the weather adjustment in PJM.

PJM does not explicitly require metering of on-site generation that could be used for demand reductions, but metering of on-site generation is required if that on-site generator is the only source of demand reduction.

PJM, in evaluating and auditing submitted settlements, does consider whether on-site generation used explicitly for facilitating load reductions or whether on-site generation is used in the course of normal business operations.[87] PJM does not have explicit rules on how it will handle generation in determining the CBL.

[83] *Id*. p. 8
[84] PJM Interconnection, *PJM Manual 11,* Section 10.4.2
[85] In PJM loads must choose the CBL they are using and demonstrate that it meets the accuracy requirement.
[86] PJM refers top this as a Symmetric Additive Adjustment (SAA).
[87] This evaluation is done manually by staff. The idea of generation being used in normal business operation is whether the generation would have been running or not absent the demand response activity being submitted for settlement.

3.4.3 ISO-NE[88]

ISO-NE is in the process of changing their CBL methodology for demand response with a switchover date of June 1, 2018, as part of the move toward integrating demand response into 5-minute energy market dispatch and co-optimization with ancillary services. The current methodology[89] treats all days the same, regardless of weekday or weekend and holiday and has a longer weather adjustment window. The current methodology will be maintained for weekdays only. And unlike other ISO/RTO markets, ISO-NE measures their baselines on a 5-minute interval basis consistent with the requirement for 5-minute interval data.

The current methodology that applies for all days uses the average of the last 10 non-event days with a look-back window of 30 days. The current weather adjustment is 2-hour period 2.5 hours before the event, and the adjustment cannot result in a CBL value that is greater than the maximum facility load.

Starting June 1, 2018,[90] the ISO-NE methodology adds separate baselines for Saturdays alone, and then Sundays and Holidays combined. For these weekend day-types the CBL is the average of the last 5 non-event days. With the movement to 5-minute settlements integrating demand response into 5-minute dispatch and co-optimization of energy and ancillary services, the adjustment period is shortened to a 15-minute window that runs up to 10 minutes prior to the start of the demand reduction event. ISO-NE believes this shortened window will provide a more accurate weather adjustment than the previous method.

ISO-NE explicitly considers different metering configurations.[91] If an on-site generator is used only as a real-time emergency generation asset, and it is the only generator on-site, it need not be directly metered. However, in other configurations with on-site generation, the on-site generation must be directly metered to count toward the total facility load which includes the generation from

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[88] ISO-NE, *Section III, Market Rule 1 Standard Market Design,* Section III.8 Demand Response Baselines, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[89] ISO-NE, *Section III, Market Rule 1 Standard Market Design,* Section III.8A
[90] ISO-NE, *Section III, Market Rule 1 Standard Market Design,* Section III.8B
[91] ISO-NE, *ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR,* Revision: 6 Effective Date: June 1, 2014, Section 5.6

the on-site generation. So, while there is an exception to metering on-site generation, the general rule is that it must be metered.[92]

3.4.4 CAISO[93]

The current CAISO energy market CBL uses the average of the 10 most recent non-event days for weekdays with a look-back window of 45 days. If there are not 10 non-event days in the look-back window the CBL can be determined with a minimum of 5 non-event days. Weekends and holidays are treated as a single day-type and the CBL uses the last 4 non-event days out of the 45 day look-back window.

CBLs are calculated on an hourly basis, and notes that for sites with 5-minute interval meter data, the intervals will be rolled up to get an hourly baseline. Weather adjustments are made with a 3 hour window starting 4 hours prior to the demand reduction event. The maximum adjustment is plus or minus 20 percent.

CAISO explicitly requires on-site generation be separately metered/sub-metered for monitoring and settlement purposes for demand response.[94] Moreover, a generation output baseline is determined to discern between normal operations to serve facility load or for running generation only to reduce load during an event. The generation output baseline is the same average of the last 10 non-event days to establish the baseline.

With respect to storage behind the meter used to facilitate demand reductions, its output is treated like any other generator output, but when charging, generation output is assumed to be zero.

3.4.4.1 Nexant Report to the CAISO Baseline Accuracy Working Group[95]

The CAISO through its Baseline Accuracy Working Group has recently examined different CBL methodologies that could be used to get a more accurate CBL for use in wholesale market transactions.

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[92] ISO-NE, *Section III, Market Rule 1 Standard Market Design*, Appendix E, Demand Response, Appendix E1, Sections 7 and 8.
[93] CAISO, *Demand Response User Guide*, Version 4.3, May 5, 2017, p. 150-170.
[94] *Id*. p. 164-170
[95] Nexant, *California ISO Baseline Accuracy Work Group Proposal*, April 4, 2017.

One of the key findings from the Nexant Report is that current CBL in CAISO works well for medium to large commercial and industrial (C&I) customers, but not smaller loads like residential loads. Nexant tested multiple CBL methodologies.[96] These included the use of control groups and different weather day-matching methods. Two different types of control groups were tested: 1) randomized control trial where a subset of participants is randomly selected not to respond during the event period; and 2) a matched group of non-participants which has the same characteristics as those participants that can respond to the event. Nexant also tested various same-day weather adjustments.[97]

With respect to C&I customers for demand reduction settlements, Nexant recommended the following as possible CBLs along with corresponding weather adjustments:[98]

1. For weekdays the continued use of the average of the last 10 non-event days which had worked well previously along with a +/-20 percent weather adjustment;
2. For weekends and holidays, the continued use of the average of the last 4 non-event days which had worked well previously along with a +/-20 percent weather adjustment;
3. The use of control groups with a +/-40 percent weather adjustment for both weekdays and weekends;
4. The average of the 4 days with the most similar weather over the past 3 months using maximum temperatures with a +/-40% weather adjustment for both weekdays and weekends.

The adjustment window is reduced to a 2-hour window four hour prior to the event.

For residential customers, a segmentation not currently in place for the CAISO, Nexant recommended the following as possible CBLs along with corresponding weather adjustments[99]

1. For weekdays the use of the average of the 5 highest of the last 10 non-event days along with a +/-40 percent weather adjustment;

[96] *Id.* Section 1, p. 4.
[97] *Id.* Section 1, p. 5.
[98] *Id.* Section 3, Table 3-1, p. 4. Note the pages in the Nexant report start over again at Page 1 after the first 12-13 pages.
[99] *Id.*

2. For weekends and holidays, the use of the average of the highest 3 of the last 5 non-event days with a +/-40 percent weather adjustment;
3. The use of control groups with a +/-40 percent weather adjustment for both weekdays and weekends;
4. The average of the 4 days with the most similar weather over the past 3 months using maximum temperatures with a +/-40% weather adjustment for both weekdays and weekends.

According to Nexant the use of randomized control groups resulted in the most accurate baselines for residential and commercial air conditioning cycling programs, but this requires interval meter data for all sites in both the active participating group and the control group. Additionally, Nexant recommends three principles for validation of the control group:[100]

- Little to no bias. The bias, if any, should be small enough to be corrected through same-day weather adjustments.
- 90/10 precision. That is the error should be less than 10 percent with a 90 percent confidence.
- Minimum sample size of 150.

3.5 Energy Market Baseline Analysis and Recommendations

3.5.1 Energy Market CBL Analysis and Recommendation

It has been 7 years since there has been any demand reduction activity in the NYISO energy markets through the Day-ahead Demand Response Program. But with low energy prices there is little reason to for customers to reduce consumption in response to prices that are already quite low at the wholesale level.

As it stands today, the current CBL methodology is still an effective baseline going forward. In the 2014 DNV KEMA study for the NYISO it was one of the better performers. The recent study by Nexant for the CAISO BAWG also indicted the “5 of 10” baseline with weather adjustments

[100] *Id.* Section 4, p. 12-13

worked well for California residential customers, and it may be the case this same methodology already in place in the NYISO would work well for New York residential customers.

However, there were other methodologies that also worked well in the DNV KEMA study that are already being used by the CAISO and ISO-NE and that is the use of the so-called “10 in 10” or the average of the last 10 non-event days that NYISO may wish to consider adding as a potential CBLs option to achieve even better accuracy.

As noted at the beginning of this section, the energy market CBL can be used for either day-ahead market or real-time energy market participation since the CBL is measured based on real-time loads as opposed to only financially settled loads day-ahead.

3.5.2 Weather Adjustment Analysis and Recommendation

All RTO/ISO CBL methods use some type of in-day adjustment that handles variations in weather. And given the day-to-day variability in weather, the basic CBL calculation looking at averages over the past 5 to 10 non-event days likely does not capture weather going into an event day. Consequently, weather adjustment mechanisms, like the one the NYISO uses should remain in place as part of the overall CBL formulation. And while there are incentives for sites engaging in demand reduction to try and increase consumption to increase the CBL, the cap of +/-20 percent at least limits the potential gains from such a strategy.

The 2014 DNV KEMA study for NYISO went as far as to note a +/-50 percent adjustment cap would capture 99 percent of the adjustments needed in the study with an uncapped adjustment. But DNV KEMA also noted in the same study that the current +/- 20 percent cap covered 95 percent of the adjustments. Moreover, the top two percentiles of adjustments could be accounted for either by data problems or other anomalies or highly variable loads.

However, ISO-NE only allows the adjustment up to the maximum facility load, a parameter submitted to ISO-NE, and such an addition to capping this adjustment can ensure a CBL never rises above this threshold level of the maximum consumption under any conditions.

Nexant, in its study for the CAISO BAWG, also has recommended larger adjustment caps of +/-40 percent in their recommended CBLs, though without the same detailed explanation as to why these values made sense except for the obvious improving accuracy on an event day.

The recommendation is to stay with the current +/-20 percent cap on weather adjustments as it is today knowing it captures 95 percent of adjustments made when there was no adjustment cap in the

DNV KEMA study. This seems to provide good accuracy but guarding against anomalous outcomes and limiting opportunities for strategic behavior.

3.5.3 Highly Variable Loads Analysis and Recommendation

Highly variable loads are those loads for which a CBL does not adequately match the observed load levels. The reason some loads may be highly variable may be due to the nature of production processes. With DER, this could be related to the intermittent output of DER such as solar and wind, or the use of storage with periodic injections and withdrawals of energy from the system. Of the ISO/RTOs surveyed, only PJM has defined highly variable loads as those loads with a CBL having a relative root mean square error (RRMSE) of more than 20 percent.[101] For the use of control groups to determine baselines, Nexant has indicated a RRMSE of only 10 percent with a 90 percent confidence interval.[102]

Moreover, the DNV KEMA study for the NYISO indicated, there may be a need to limit the ability of highly variable loads to participate in the NYISO if there are no effective or accurate baselines available. For loads that may be deemed highly variable, there may be a different set of baselines that could be employed to arrive at the desired precision as one CBL may not fit all situations.[103] As a result, for loads that do not fit well with the standard or default CBL approaches, other CBL methods could be introduced that more accurately reflect what load would have consumed absent the demand reduction as has been the case in PJM.

While highly variable loads should also be able to participate in the NYISO wholesale markets, the recommendation is that the use of any CBL should at least match the PJM error standard of a RRMSE of no more than 20 percent, and open the possibility to a highly variable load providing an alternate CBL that can achieve this level of accuracy similar to PJM. Without such an accuracy standard, the integrity of the demand reductions submitted into the market could be called into question.

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[101] PJM Interconnection, *PJM Manual 11*, Section 10.4.2.
[102] Nexant, Section 4, p. 14.
[103] For example, PJM has listed multiple CBLs in its Manual 11 for just the purpose and the Nexant Study for the CAISO has also recommended different baseline methods for different customer classes as discussed below.

3.5.4 Metering On-Site Generation/DER Analysis and Recommendations

The CAISO and ISO-NE, as a practical matter, require on-site generation behind the meter to be directly metered. PJM does not, though it does accounts for directly metered generation in measuring demand reductions in some cases. Currently, the NYISO does not require direct metering of on-site generation being used to facilitate load reductions for settlement. But the NYISO does have a sense of generation present at a customer site depending on how they categorize their site as being Type B or Type G.

Directly metering on-site generation or DER can help in discerning whether the generation/DER is being used regularly to help meet facility load, or whether it is only used to reduce load during emergency or high price events. As DER in New York may be called upon to implement "distribution solutions" and run in a pattern that is not predictable from a NYISO market or operations perspective, or as storage devices serving as DER act as both load and generation, or intermittent renewables makes facility net load more variable, having the visibility of what that DER is doing independent of the load will become more critical to computing baselines and providing operational visibility.

Given the likely increase in DER on the NYISO system as anticipated in the DER Roadmap, it is recommended to start requiring any on-site generation or DER to be directly metered. Furthermore, like the CAISO, it is recommended that on-site generation/DER output be baselined to provide visibility into how that generation runs to support load that may be submitting demand reductions into the NYISO market. The DER/on-site generation baselining should initially follow the CAISO model of the average output over the last 10 days to cover what would be "normal operations" versus operations for primarily facilitating demand reductions. While this differs from the overall NYISO highest 5 of 10 baseline, it will provide a better sense of overall patterns of output. This need for metering will also be essential if some DER wishes to participate in the NYISO markets while also receiving compensation for distribution system activity under retail tariffs.

3.5.5 DER and Energy Market Baselines with Dual VDER and NYISO Participation Recommendation

Going forward, some DER may be receiving compensation under the NYPSC VDER Tariff which compensates resources for energy produced at the applicable LBMP.

In the short-term, dual participation of resources receiving compensation under the NYPSC VDER Tariff should not be permitted to participate in the NYISO energy market. This recommendation does not preclude DER that are operating under contracts with the incumbent distribution utilities to provide Non-Wires Alternatives, and not under the VDER Tariff, from participating in the NYISO wholesale market. Services provided to utilities that fall outside of the VDER Tariff should be evaluated to ensure that DER are not compensated twice for the same service.

However, the NYISO should evaluate if there is a legitimate means to compensate DER for ancillary services without compensating it twice for energy and capacity if the DER is also being compensated under the VDER Tariff. While VDER Tariff would require at least hourly interval metering on the DER, it would mean the overall load would need to be metered as well to discern between load reductions that could be compensated by the NYISO, from DER that is being compensated under the VDER Tariff. Moreover, the incentives to provide energy to the NYISO or under the VDER Tariff should be the same: prevailing LBMP. This means compensation is the same regardless of being in the NYISO market directly or taking compensation under the VDER Tariff.

3.5.6 Use of Control Groups is Not Recommended at This Time

The use of control groups to determine CBLs and weather adjustments has great appeal if they are used properly. Control groups should mirror the groups actually participating in the market and be free of bias and precise in their measures as described by Nexant in their study for the CAISO. However, the use of control groups also requires a larger roll out of interval metering, and requires interval metering for the control group in spite of the fact they do not participate in the market. This is something the NYISO should study more closely in anticipation of a wider rollout of interval metering that will be required under the VDER tariff recently approved by the NYPSC. But until interval metering becomes more widely deployed, the use of control groups will need to wait in the NYISO.

Moreover, one of the unanswered questions of the control group recommendations from Nexant is why the cap on the weather adjustment recommended (+/- 40 percent) was so much larger than the adjustment currently in place in the CAISO at +/-20 percent. The report was silent on this aspect. If the purpose of the same day weather adjustment is to correct for under or over forecasting the CBL, a larger adjustment factor would seem to indicate the use of control groups leads to less accurate CBL’s overall than the average of the last 10 non-event days, or that residential loads are much more variable than medium to large C&I loads.

3.6 Aggregation Issues with Baselines

The concept of aggregating small resources into a single larger resource for demand response or DER is well understood and accepted. The NYISO has already proposed a form of aggregation for new DER coming on the system by permitting aggregations behind a single transmission bus to best ensure transmission constraint control.[104]

One question that has come up is the aggregation of baselines. Should the aggregation of baselines be the sum of all the baselines of each site that is part of a demand resource (or in the alternative, the maximum generation capability of DER), or should the baseline be of the aggregate resource rather than the sum of the parts?

The first intuitive feel is that the baseline of the aggregate resource should equal the sum of the baselines of all the sites of which the aggregated resource is comprised. This would certainly be true for DER that is generation capacity simply adding up the capacity for all the resources.

This issue does not come up in PJM,[105] which uses a most recent 5 non-event day baseline for the energy market, nor does it come up in the CAISO or ISO-NE which uses the last 10 non-event days as the baseline. All the sites in the aggregated demand resource in these cases would all have the same non-event days that go into the baseline since none of them would be called separately from the other sites.

But since the NYISO uses the highest 5 days, out of the last 10 non-event days for the energy market baseline, the days counting toward the baseline may differ and the sum of the baselines may not equal the aggregate baseline. A great example to see this phenomenon comes from the Day-ahead Demand Response Program Manual.[106] Table 5.1 and associated calculations from Section 5.2 is replicated below.

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[104] NYISO, *DER Roadmap*, p.17-19.
[105] PJM, *PJM Manual 11*, Section 10.5.2. explicitly states for settlement for a aggregated demand resource, it is the sum of the individual CBLs less the sum of the individual metered loads.
[106] NYISO, *Day-Ahead Demand Response Program Manual,* July 2003. Available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/dadrp_mnl.pdf.

Table 5.1 – Illustrating Non-Coincident CBL Calculation for Aggregated Resources

	Day(n-2)	Day(n-3)	Day(n-4)	Day(n-5)	Day(n-6)	Day(n-7)	Day(n-8)	Day(n-9)	Day(n-10)	Day(n-11)
DSR #1	3.2	4.5	3.3	4.2	1.1	1.3	4.5	3.6	3.2	2.3
DSR #2	7.2	7.2	4.5	7.3	7.3	4.9	4.9	6.2	6.3	6.7

The CBL for DSR #1 is given as (4.5 + 3.3 + 4.2 + 4.5 + 3.6)/5 = 4.02 MWh.

The CBL for DSR #2 is given as (7.2 + 7.2 + 7.3 + 7.3 + 6.7)/5 = 7.14 MWh.

The composite non-coincident CBL for the aggregated resources would be 4.02 + 7.14 = 11.16 MWh. The CBL is termed non-coincident because different days are used for each individual CBL calculation.

Because each site uses the highest 5 of the last 10 non-event days, the CBLs summed up are equal to 11.16 MWh But, if only the highest 5 days from the aggregated source were used, those would be Day n-2 (10.4 MWh), Day n-3 (11.7 MWh), Day n-5 (11.5 MWh), Day n-9 (9.8 MWh), and Day n-10 (9.5 MWh). Note that 3 of the 5 highest days for the aggregate resource are missing at least one of the sites, and one day misses all of the sites that are counted in their individual baselines. The average of the aggregated resource is 10.58, or 0.58 MWh lower than the sum of the baselines.

But using the Table 5-1 example, and assuming all 10 days are used in the baseline, the individual CBL for DSR#1 would be 3.12. The individual CBL for DSR#2 would be 6.25. These sum to 9.37 which is also the aggregate baseline. And given the performance of the current baseline as shown in the DNV KEMA study, this property of the highest 5 non-event days out of the past 10 non-event days is not a reason to change energy market CBLs at this time. The recommendation is for the NYISO to continue the practice of adding up the CBLs from each site to get to the aggregate resource CBL.

4 Capacity Market Baselines

Capacity market baselines serve the same function as energy market baselines in that they are designed to provide a measurement of consumption absent the action to reduce demand and provide an upper bound on how much demand reduction is available when needed by the system. And like an energy market baseline, a capacity market baseline can also provide a benchmark from which performance can be measured for delivering the capacity to the system when needed for event compliance (outside the scope of the study) or to adjust the amount of demand reduction available based upon historic performance.

In some ISO/RTO markets with centralized capacity markets such as the NYISO and PJM, demand response resources providing capacity are typically called when the system is entering emergency conditions which often correspond to peak demand periods, but can be called at any time they are needed to ensure reliability. In other markets like ISO-NE, demand response is being fully integrated in the energy market dispatch along with being a source of capacity. The capacity market requirements are driven by the peak period demand and therefore capacity market baselines for demand response are often tied to what is available during peak load conditions and the peak demand drives how those capacity costs are allocated.

Capacity can be viewed as a derivative, in the form of a physical call option to have the energy commodity delivered. A commodity market driven baseline would be akin to a load or customer site taking a financial position on capacity up front buying what would be required to serve its peak load absent any reductions, and then selling part of that position back to the market with the promise to reduce demand such that its consumption would be no higher than its net position as necessary for system reliability. From a generation perspective, capacity positions can be sold forward as a physical call option on its energy to be delivered to the system when needed.

Implicitly in all markets where there is a centralized capacity market: ISO-NE, NYISO, and PJM, loads do buy their forward position when the capacity market clears knowing they will be allocated costs of capacity based upon their contribution to the system peak load. This is true in all the above cited capacity markets, albeit the allocations differ in small ways.[107]

The question then arises how this capacity from demand response is accounted for or sold back and how the measured performance with respect to that obligation to sell back capacity adjusts how much demand reduction can be sold in the future.

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[107] In PJM, each load is allocated the cost of capacity based on its contribution to the top five coincident peak hours. *See PJM Manual 19,* Section 4.3, and PJM Interconnection, LLC, *PJM Manual 18: PJM Capacity Market* Revision: 38 Effective Date: July 27, 2017, (PJM Manual 18) Sections 7.3 and 7.4, available at http://pjm.com/-/media/documents/manuals/m18.ashx. In the NYISO load is allocated capacity based on its contribution to the coincident peak hour. *See* NYISO, *NYISO Installed Capacity Manual,* Version 6.37, August 25, 2017, Section 3.4, available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf. In ISO-NE, load is allocated capacity cost based on the contribution to coincident peak load. *See* ISO-NE, *Section III, Market Rule 1 Standard Market Design,* Section III.13.7.3.1 available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

4.1 Maximum Quantity of Demand Reductions

There are two methods currently in play for measuring the maximum quantity of demand reductions available. The first is intuitively attractive in that the capacity requirements are usually a function of the system peak load condition, so a measure of the peak load from a load customer during the system coincident peak is a natural baseline for demand reductions available to the market.

The second is to use an estimate of an energy market baseline, as discussed in the previous section, during system peak periods, maybe both summer and winter peak periods, as the baseline for what reductions are available. Logically, this energy market baseline should closely track a load customer's peak load during the system coincident peak in much the same way as the first method does. In both cases, the maximum demand reduction available should be a function of the peak load during the system coincident peak.

4.1.1 Adjusting the Maximum Quantity Based on Historic Performance Delivering Demand Reductions

In much the same way that historic generation performance, in the form of the forced outage rate, is a determinant of how much capacity a generation resource can offer into the capacity market, the historic performance of demand response can also be a determinant of how much capacity in the form of demand reductions can be offered into the capacity market. The historic performance measurement can be handled in two different ways. One way is to measure performance based on the amount of committed reduction that was achieved. In this way demand response is treated as if it were a generator with the energy market CBL being used as the "maximum reduction capability" in real-time. This form of performance measure just checks for the metered load, or energy market CBL, prior to the event, and the metered load during the event. If the difference is at least as great as the committed reduction, then the load or customer site complied with its performance obligation. The load consumed just prior to the event can be above or below the amount of capacity the load was obligated to purchase. This first method of measuring performance implicitly treats the load reduction exactly like a generator in that when the event is called, the load reduction can be observed on the meter. If the demand response "under-performed," then an adjustment can be made to how much capacity can be offered in future periods to account for the expected performance.

The other method for measuring performance is to take the purchased capacity obligation prior to the load reduction or baseline maximum that can be sold, less the committed reduction or capacity sold back, to get what looks like a maximum firm load for the customer site/load. If the metered load during the event is at or below the maximum firm load, the customer site/load is given credit for complying regardless of what the consumption was prior to the event. The second method for measuring performance treats the load as if it has purchased the right to consume up to its maximum firm demand rather than as a generation resource. Its actual reduction measured as the metered load prior to the event and the maximum firm load is not what counts, but just the idea the customer site/load got down to or below its maximum firm demand. Again, if the demand response "under-performed," then an adjustment can be made to how much capacity can be offered in future periods to account for the expected performance.

4.2 NYISO

The current maximum quantity of demand reductions that can be sold into the Installed Capacity Market by Special Case Resources (SCR) is known as the Average Coincident Load (ACL). The ACL is the average of the customer's highest 20 one-hour peak loads taken from the top 40 coincident peak hours for the applicable Load Zone during the prior like six-month capability period.[108] The ICAP value of the SCR is equal to the ACL less the committed maximum demand, adjusted for transmission loss factors.[109]

Performance during an event is measured by the ability to deliver the committed ICAP value through what is equivalent to comparing the metered load to the committed maximum demand (or the ICAP to on-site generation output), rather than actual metered load reductions during the event.[110] So long as the SCR is consuming at or below is committed maximum demand, it is considered to be fully performing and meeting its capacity obligation.[111] This performance is then used to develop the actual unforced capability than can be offered in future periods into the capacity market to adjust for expected performance that has been observed historically.[112]

In this way, the NYISO treatment of demand reductions as capacity differs from the PJM treatment and ISO-NE treatment where historic performance is not used to reduce the demand reductions

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[108] NYISO, *NYISO Installed Capacity Manual*, Version 6.37, August 25, 2017, Section 4.12.2.1.1. and NYISO, *Market Services Tariff*, Section 5.12.11.1.1

[109] NYISO, *NYISO Installed Capacity Manual*, Version 6.37, August 25, 2017, Section 4.12.2.1.1.

[110] *Id.* The committed maximum demand is the benchmark by which performance is measured for SCRs as shown in Section 4.12.2.1.1 and associated subsections.

[111] *Id.*, p. 4-60 to 4-62.

[112] *Id.*

available to be offered to the capacity market, but to measure and penalize (or reward) performance during an event. Still, the performance measures in other markets can provide some insight regarding how to adjust the demand reduction capability to be offered in future periods.

4.3 PJM

For demand response in PJM, the maximum quantity of demand reduction that can be submitted into the capacity market by a load customer is based on the most recent peak load contribution which is based on the average load during five coincident peak loads hours, and which coincides with the manner for which capacity costs are allocated.[113]

Performance measurement in PJM is not used to adjust the amount of capacity available to be offered in future capacity auctions, as is the case in the NYISO, but is a penalty/reward driven measurement during an event. In this context, PJM relies on two methods for measuring performance. The first is identical to the idea of ensuring that a load or customer site committing to a load reduction gets down to maximum firm demand, or what PJM calls the Firm Service Level.[114] The second is a hybrid of measuring the actual load reduction during the event based on the energy market CBL, the peak load obligation of the customer site/load, and the metered load during the event. This is known as Guaranteed Load Drop in PJM.[115] Performance takes the minimum of the peak load contribution (PLC) and the CBL during the event less the metered load and compares it to the committed reduction: min{PLC, CBL} – metered load ≥ committed reduction.[116] The second method treats the committed reduction like a generator if its CBL is less than the PLC, except that it cannot sell back more capacity than is purchased.

PJM’s second method guards against the ability of a customer site/load to increase its load above its peak load contribution (the capacity for which PJM has purchased to ensure reliability) and then drop load to what is effectively a higher metered level than PJM was expecting. This performance measurement is also consistent with reliability needs to meet load on the peak day as there should be no financial incentive to drive the system into an emergency condition to get paid to reduce load but to a level less than would be anticipated by the RTO. For example, suppose a load signed up to

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[113] PJM Interconnection, LLC, *PJM Manual 18,* Section 4.3.7
[114] *Id.* Sections 8.7 and 8.7A
[115] *Id.* Sections 8.7 and 8.7A
[116] *Id.* Sections 8.7 and 8.7A

drop 20 MW of load and had a PLC absent demand response of 100 MW. If the load increased consumption during the event day (the day it was required to drop load) to get its CBL, with an adjustment up to 120 MW prior to the event, the load would then only need to reduce to 100 MW, its PLC absent demand response. But PJM was anticipating only serving at most 80 MW of this load from a reliability perspective, yet in this scenario if the minimum of the PLC and CBL is not considered, the load would be considered complying even though it had not reduced its load below its PLC absent demand response.

4.4 ISO-NE

ISO-NE allocates costs in much the same way as PJM and NYISO, based on the contribution to system peak load, but for a demand response resource, the demand reduction value is not reconstituted back into the peak load contribution for the capacity obligation.[117] This is different from the PJM methodology which "adds back" the demand response amount into the peak load obligation for the purposes of allocating capacity costs.[118] But rather than capping the amount of capacity that can be sold based on what is purchased for the load/customer site in the capacity market, ISO-NE mandates that demand reduction values be calculated consistent with the energy market baselines used for energy market settlements.[119]

ISO-NE measures performance solely based upon the energy market CBL that is in place going into the event.[120] In this way, ISO-NE treats the customer site/load as if it were a generator, expecting to get a reduction in metered load during the event equal to the committed reduction value that is also based on the energy market CBL. That is the CBL less the metered load during the event should be at least equal to the committed reduction value.[121] Like PJM, performance measurement is a penalty/reward driven metric rather than a means by which to discount how much capacity can be offered in future auctions.

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[117] ISO-NE, *Section III, Market Rule 1 Standard Market Design,* Section III.13.7.3.1.
[118] PJM Interconnection, LLC, *PJM Manual 19,* Appendix A
[119] ISO-NE, *Section III, Market Rule 1 Standard Market Design,* Section III.13.1.4.3.2 referencing Sections III.8A and III.8B that defines the energy market baselines. Note that adjustments to the baseline cannot exceed the maximum facility load which implies a *de facto* cap on how much demand reduction could be sold to the market.
[120] ISO-NE, *Section III, Market Rule 1 Standard Market Design,* Sections III.13.7.1.5.7.3 and III.7.1.5.7.3.1
[121] *Id.*

ISO-NE has opted for this different design as its Pay-for-Performance design is meant to mimic the incentives of an energy only market regarding generator performance, such that any resources, whether it is a generator or committed demand reduction are treated the same way in the energy market and in the capacity market. Moreover, ISO-NE is integrating demand response into its five-minute dispatch and co-optimization of the energy and ancillary service markets, so treating demand reductions and generation in the same way across all markets makes sense in their context.

4.5 Analysis of Capacity Baselines Maximum ICAP from Demand Response

From a commodity market perspective, a load or customer site should not be able to sell back more capacity than they have bought or for which they are obligated to pay. To be able to sell back more than it paid for would imply the ability to sell back a demand reduction that is not available or in the possession of the load. This idea is identical to the CBL in a commodity market context discussed previously. Moreover, the amount of capacity that can be sold back should be subject to some kind of performance measure that accounts for what is actually expected to be delivered.

From this perspective, the ideal maximum quantity that could be offered from a demand response resource should be tied to the allocation of costs (how much capacity is being purchased on behalf of the load or customer site). For example, if cost allocation of capacity is based upon the contribution to coincident peak load, then the coincident peak used to allocate costs should be used as the maximum value to be sold back. This is exactly how the PJM capacity market baseline (or maximum offer of demand reduction) is defined. PJM caps the maximum value that can be sold back at what is purchased based on the peak load contribution of the load, with add-backs for demand response. But in the PJM case, there is no accounting for how much is expected to be delivered based on historic performance.

However, only being able to sell back less than that maximum amount could hinder the ability to provide demand reductions that are available to ensure resource adequacy or help a load completely offset its capacity costs if it chooses to do so.

ISO-NE on the other hand does not cap the amount of capacity that can be offered from demand response resources based on what has been allocated to the load providing demand response, but demand response and generators are treated the same way in the capacity market and in the energy market, and demand reductions are not added back to the peak load obligations. While there is no buying and selling back of capacity in ISO-NE like in PJM, the end result is observationally equivalent.

The NYISO uses the ACL for SCRs as a proxy for the customer's contribution toward the coincident system peak and to limit the maximum amount of demand reductions that can be offered, and adjusts the unforced capacity to reflect historical performance. This maximum baseline concept is similar in spirit to the idea of capping demand reductions at the peak load contribution in PJM. The NYISO method also accounts for past performance to adjust the amount of demand reductions, in unforced capacity terms, that can be offered in the capacity market in future periods.

With respect to the use of the ACL, a 2014 study on baselines for SCRs by DNV-KEMA shows that the ACL is higher than the load in the top five coincident peak hours by 6-8 percent to provide an indication that the ACL may allow the SCR to sell back more capacity than is purchased.[122] Moreover, the DNV-KEMA study indicated the use of the NYISO CBL baseline methods matched the loads on peak days better than the ACL measures which were higher than loads on peak days.[123] Such a condition could result in the NYISO counting on more capacity than is actually available during the system coincident peaks when the system is likely most stressed. The reason the energy market baseline looks so appealing from a maximum offer standpoint is that the CBL for peak hours matches more closely the coincident peak load than the ACL does in the DNV KEMA study.

What is required is consistency in the methodology. Demand reductions in ISO-NE reduces the obligation up front such that no capacity is being bought that needs to be sold back. Effectively, demand response is being treated like a generator in how much capacity it offers and is evaluated based on the energy market baseline method when the energy is needed. PJM's firm service level is consistent in treating the net demand for capacity as being on the demand-side of the market, and caps the maximum offer of demand response resources at the peak load contribution which maps to capacity purchases absent any demand response. PJM's GLD option mixes the load and generation concepts between maximum offers and how performance is measured.

NYISO is using the ACL as the maximum quantity that can be offered by the SCRs, similar in concept to the PJM peak load contribution, except the ACL allows more capacity to be offered

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[122] DNV-KEMA, Inc., *NYISO SCR Baseline Study*, March 2014, p. 9-10. Available at http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Demand_Response/Special_Case_Resource_ICAP_Program/NYISO%202013%20SCR%20Baseline%20Study%20Report-final.pdf.
[123] *Id.* p. 11-13.

than is actually purchased or accounted for in the load's capacity obligation. In addition, NYISO allows for adjustments downward for unforced capacity based on historic performance.

4.5.1 Recommendation Regarding the Maximum ICAP that can be Offered or Awarded for Demand Response

Today, NYISO considers SCRs a supplier of capacity like a generator. However, the detailed workings of the NYISO offer and historic performance baselines for SCRs can also be viewed as placing SCRs on the demand-side of the market offering demand reductions by selling back capacity that has already been purchased. SCRs declare a committed maximum demand, which is akin to the firm service level concept in PJM, and the nominated value of the load reduction is the difference between the ACL and the committed maximum demand. The amount of unforced capacity that can be offered is adjusted downward based on historic performance in a manner similar to a generator, but historic performance is measured based on metered load relative to the committed maximum demand.[124] This structure would also then be entirely consistent with pure commodity market baseline in which only capacity procured on the demand-side of the market can be sold back as a demand reduction. The NYISO should consider reflecting the idea that demand reductions are different from energy supplied from generation which is consistent with where PJM has gone with its firm service level concept where the nominated capacity value is the peak load contribution less the firm service level. This structure also makes it easier for loads that are highly variable to offer demand reductions into the capacity market in that neither their baseline nor historic performance adjustment is dependent on an energy market baseline, but on a more predictable foundation in which they can offer demand reductions if they are capable.

In the short term, the recommendation is for the NYISO to first consider treating demand response different from energy supplied from generation, similar to the firm service level concept. Alternatively, the NYISO should keep the existing SCR structure for demand response, including the use of historic performance measures to adjust the maximum reductions, in unforced capacity terms, that can be offered, with one change: the maximum reduction offered from demand response resources, even those using on-site generation to facilitate reductions, should be no more than the contribution to coincident peak load, a value that DNV KEMA showed was consistently less than

[124] If performance was perfect, then the maximum amount of ICAP that can be offered in would equal that of UCAP. Otherwise if performance is not perfect, the maximum amount of UCAP would be less than that of ICAP.

that ACL value by 6-8%. As it turns out, the energy market CBL matches the coincident peak load much better than the ACL. Furthermore, contributions to the coincident peak drive the installed reserve margin determination, capacity procurement, and matches how capacity costs are allocated to load serving entities.

For DER that does not include any demand response, DER can be treated like a traditional generator with its maximum capacity as the limit on what it can offer into the capacity market with adjustments made for historic performance in the same way as traditional generators are treated. This treatment would be comparable to DER that are net loads offering demand response as described above.

4.5.2 DER and Capacity Baselines with Dual VDER and NYISO Participation Recommendation

On-site generation or storage being used to facilitate demand reductions can be treated like any other generator used to provide demand reductions in the NYISO today. Consistent with the recommendations regarding metering/sub-metering of on-site generation or storage being used to facilitate demand response for settlement in the NYISO energy markets, non-demand response DER should be metered/sub-metered for participation in the NYISO capacity markets. This is even of greater import since DER could also receive, in the alternative, compensation under the NYPSC VDER Tariff, while any associated demand reductions independent of the VDER Tariff would not be eligible for compensation under VDER Tariff.

Going forward, some DER eligible to receive compensation under the NYPSC VDER Tariff may be facilitating demand reductions in the capacity market, and thus could receive double compensation for the reduction of capacity requirements if also participating in the NYISO capacity market. The metering requirement on non-demand response DER can help ensure this kind of double compensation does not take place and only NYISO eligible demand reductions are counted in the NYISO capacity market.

In the short-term, dual participation for DER receiving compensation through the NYPSC VDER Tariff for capacity and the NYISO capacity market should not be permitted. To allow dual participation would not only require explicit metering on the DER, but it would also require checking the meter data against retail settlements to parse out the capacity provided at retail to the load serving entity, and the capacity provided to NYISO. Second, the incentives to provide capacity to NYISO or to be compensated through the retail tariff should theoretically be the same so requiring the DER to make this choice would not be onerous or deprive the DER of compensation for capacity it provides. This recommendation does not preclude DER that are operating under contracts with the incumbent distribution utilities to provide Non-Wires Alternatives, and not under the VDER Tariff, from participating in the NYISO wholesale market. Services provided to utilities that fall outside of the VDER Tariff should be evaluated to ensure that DER are not compensated twice for the same service.

5 Ancillary Service Market Participation of DR and DER

The surveyed ISO/RTO markets differ on how and where DR and DER such as storage participate in ancillary service markets. One common theme is baselines based on historical data, in the sense of energy and capacity markets as discussed in the previous two sections, are not employed. This is likely a consequence to the existing requirements for metering, telemetry, testing, prequalification and performance measurement as needed by the ISOs/RTOs to qualify a reserve or regulation supplier. Since the real-time performance data from demand response and other DER is a more accurate measure of what it has supplied, it is used in lieu of establishing baseline methodology based on historical meter data.

For example, the provision of regulation and frequency response requires a resource, whether it is generation, load, or storage, be able to respond to AGC basepoint signals and to increase output/reduce consumption or decrease output/increase consumption from wherever they may be operating at the moment. With respect to reserves, the requirement is for a generator (or DER) to provide energy, or DR to reduce consumption, within 10 minutes or 30 minutes depending on the reserve product, up to that committed reserve capacity.

5.1 NYISO

The current rules in NYISO permit demand response operating under the Demand-Side Ancillary Service Program (DSASP) to provide operating reserves and regulation so long as it meets the metering and telemetry criteria necessary to provide these services.[125] DSASP resources that can respond to AGC signals are eligible to provide either (i) regulation and/or spinning reserve, or (ii)

[125]NYISO, *NYISO Ancillary Services Manual*, Version 4.9, October 2, 2017, Section 3.2.3.2. Available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/ancserv.pdf.

non-spinning reserve.[126] Only demand response facilitated without the use of an on-site generator may provide regulation and spinning reserve, while demand response that has on-site generation is only eligible to provide non-spinning reserve.[127] Measurement of performance in the DSASP is based on the metering levels prior to a reserve or regulation event and actual metered load during the event.[128] The capability of DR to provided reserves or regulation service is verified through pre-qualification tests.[129]

In consideration of DER that is not considered demand response, energy storage, through NYISO's Limited Energy Storage Resource (LESR) participation model, is also permitted to provide only regulation service and could move between charging (consuming energy) and discharging (injecting energy) either with a full charge or partial charge similar to a generator that is only providing regulation service.[130]

5.2 PJM

Demand response is allowed to provide synchronized reserve and regulation service subject to meeting the applicable metering and telemetry requirements, such as requiring at least 1-minute metering for reserves and the ability to receive AGC base point signals for regulation service.[131] Demand response is not eligible to provide non-synchronized reserves.[132] In order to provide both regulation and reserves, demand response must go through prequalification and training to determine their reserve and regulation capabilities.[133] Measurement of performance for a reserve event is done through metering load prior to the event and the metered load during the event.[134] Regulation performance is measured at the meter based on how quickly and accurately a resource is following the AGC dispatch signals sent from PJM.[135] Storage resources and other eligible DER

[126] *Id*. Section 6.2.3.1
[127] *Id*. Section 6.2.3.5
[128] *Id*. Section 6.2.3.11
[129] *Id*. Sections 6.12 and 6.2.4.6.1.1 and 4.11
[130] *Id*. Section 4.2, Figures 4-3 and 4-4.
[131] PJM, *PJM Manual 11*, Section 4.2.8 and 3.2.1
[132] *Id*. Section 4b.2.1
[133] *Id.* Section 4.2.8 and 3.2.1
[134] *Id.* Section 4.2.11
[135] *Id.* Section 3.2.7 through 3.2.10 show through how offers are constructed, markets clear, and settlements made how performance is measured.

can provide regulation in PJM in much the same way as in the NYISO and are treated as any other generation resources are treated.

5.3 CAISO

Unlike the NYISO and PJM, demand response cannot provide regulation, but can only provide spinning and non-spinning reserve which requires demand response to respond to 5-minute dispatch signals.[136] Like NYISO and PJM, there are pre-qualification and testing regimes that must be passed prior to being eligible to supply reserves.[137]

Storage resources participating as a Proxy Demand Response (PDR) resource are permitted to supply regulation service, and capability is based upon four times the available energy to be injected for 15 minutes, or storage may opt to be treated similar to a generator in the CAISO market through the Non-Generator Resource (NGR) model.[138]

Performance for provision of reserves is measured from the meter prior to a call for reserve and the amount of energy or demand reduction provided within the time required.[139] Regulation performance is based on whether a resource is following the AGC dispatch signals sent from the CAISO.[140]

5.4 ISO-NE

Demand response can provide reserves and regulation in the ISO-NE market, and ISO-NE continues to move toward demand response integration into the 5-minute dispatch and co-optimization. Absent any dispatch for energy, demand response capability is defined as the maximum consumption limit (in the forward reserve market or metered load in real-time

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[136] CAISO, *Demand Response Frequently Asked Questions*, February 23, 2016. Available at http://www.caiso.com/Documents/DemandResponseandProxyDemandResourcesFrequentlyAskedQuestions.pdf.
[137] CAISO, *Business Practice Manual for Market Operations,* Version 54, October 30, 2017. Sections 4.6.2 and 4.6.3. Available at https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/BPM_for_Market%20Operations_V54_clean.doc.
[138] *Id*. Section 4.6.1.
[139] CAISO, *Open Access Transmission Tariff*, available at http://www.caiso.com/Documents/ConformedTariff_asof_Jul10_2017.pdf, Sections 8.9.10, 8.9.11, 8.10.2, and 8.10.3.
[140] *Id*. Sections 8.9.9 and 8.10.1.

operations) less the minimum consumption level.[141] In this way, the capability is determined by how much the minimum consumption would be for the load, as opposed to committing to a pre-determined quantity reduction not knowing where metered load could be at the time.

With regard to regulation service, ISO-NE also allows demand response and storage to participate in this market, but they must undergo testing and pre-qualification in much the same way these resources do in other markets.[142]

Performance for reserves is measured based on the metered load before and after a reserve event and compared to the committed reserves.[143] Regulation performance is measured based on the response to AGC base point signals.[144]

5.5 Analysis and Recommendations

There is no uniformity across the surveyed ISO/RTO markets with respect to what ancillary services demand response or DER can or cannot provide, though the trend is toward more, not less participation. In all the markets, there is testing and pre-qualification that determines the capacity level resources can offer for regulation, and to some extent reserves, but there could be more specificity with regard to how reserve capability is defined for mixed DER that has both demand response and generation in an aggregation.

ISO-NE has provided a template for reserves that while treating demand response like a generator, also recognizes that demand response comes from a load by defining a minimum consumption limit so that the load can at least be assured of meeting its most essential consumption needs while committing to providing load reductions when needed to maintain grid reliability. Most markets use the metered load as the baseline prior to the needed reduction to supply reserves, but ISO-NE in its forward market uses the concept of the maximum consumption limit, which could easily look like an energy market baseline. These ISO-NE concepts easily accommodate combined demand

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[141]ISO-NE, *ISO New England Manual for Forward Reserve and Real-Time Reserve Manual M-36*, Revision 21, March 1, 2017. Sections 6.2.1 and 6.4.1. Available at https://www.iso-ne.com/static-assets/documents/2017/03/m36_forward-reserve_rev21_20170301.pdf.

[142] ISO-NE, *Market Rule 1*, Sections III.14.2 and Section III.14.9, available at https://www.iso-ne.com/static-assets/documents/2017/01/mr1_sec_14.pdf.

[143] ISO-NE, *Market Rule 1*, Section III.9.7.2.

[144] ISO-NE, Market Rule 1, Section III.14.7.

reductions with on-site generation so long as the on-site generation is only controllable by the ISO (*i.e.*, on-dispatch). On-site generation will not be solely controlled by the NYISO when DER also participate in distribution system programs, or to service local host load needs.

5.5.1 Recommendation: Use the Energy Market CBL along with a minimum consumption limit to define reserve capability in the Day-ahead Market

The NYISO should consider if ISO-NE's concept of having a maximum consumption limit for the forward reserve market is appropriate for demand response under its DER participation model. This would allow demand response to offer reserve further away from real-time. But this should be accompanied by the requirement for separate metering for the load and any DER at the same location (or aggregation) so that the load is what is baselined and monitored while the DER, which is likely intermittent, can remain a separate metered entity even if they are connected to the load facility behind the same utility meter.

5.5.2 Recommendation: Keep the Current Testing and Pre-Qualification Requirements for Regulation for DR and DER

The provision of regulation service is complicated and requires advanced metering, telemetry, and communication. In some scenarios, it may be unlikely that DER combined with a host load seeking to provide regulation service will be able to be controllable as to qualify for regulation service due to its intermittency, variability of the combined DER output and load consumption, and irregular operation of the DER, such as if the DER is being used for non-wholesale services. Yet, if there is a way for DER combined with a host load to satisfy the existing qualifications for a regulation supplier, then the rules and requirements are already in place for generators and DSASP and can be applied to DER.

5.5.3 Recommendation: Allow for the Possibility for Dual Participation between the VDER Tariff at Retail and NYISO Ancillary Services Market Participation

DER, to the extent it is eligible to receive compensation under the VDER Tariff, may also still participate in the NYISO ancillary service markets so long as there is no double compensation. For example, if a DER is providing reserves and the DER is called upon to provide energy, there need to be provisions in place to ensure the DER is not paid twice for the energy as discussed above. To the extent that DER coming on the system can satisfy the technical requirements to provide reserves and regulation, and control over dispatch between the NYISO and distribution utilities can be coordinated, and double compensation can be avoided, then there is no technical reason why

DER could not provide ancillary services if they are capable. As mentioned in a previous section, NYISO will need to evaluate how DER under the VDER Tariff may be compensated for providing ancillary services, including in the instances when the ancillary services are asked to deliver (*i.e.*, provide energy), without being compensated twice for energy or capacity.

6 Statistical Sampling for CBL Determination and Market Settlements

Statistical sampling allows DR providers represent performance from all sites through the installation of interval meters on only a subset of customers with like profiles and characteristics, where interval metering in not widely available. Sampling methods have been used to permit mass market, residential customer sites to participate in wholesale markets through aggregators that are wholesale Market Participants. Sampling methods are used derive a CBL and M&V for performance and settlement without installing interval meters on a set of aggregated DR customers and thereby reducing the cost of DR participation in wholesale power markets.

With respect to DR, sampling has been used mainly for direct load control (DLC) programs related to controlling devices such as HVAC units, hot water heaters, and pool pumps where loads for these devices are well known and understood and have similar characteristics. When broken down by device size and location, generically known as stratification, the population of sites is relatively homogenous (the same) which allows for confidence that the metered subset is representative of the entire population.[145]

6.1 NYISO

The NYISO permits Small Customer Aggregations in its Special Case Resource and Emergency Demand Response Programs, with Small Customer Aggregation rules, contained in the Emergency Demand Response Program Manual. [146] Small Customer Aggregations are subject to the same

[145] Sampling methods have also been used as part of energy efficiency M&V plans for capacity market participation in ISO-NE and PJM. An example of sampling over sites with similar characteristics for energy efficiency is for a switchover from incandescent lighting to LED lighting.
[146] NYISO, *NYISO Emergency Demand Response Program Manual*, Version 7.2, March 6, 2016, Section 2.7, available at

rules as all other resources participating in those programs with the exception that the Market Participant may use statistical sampling to measure individual resource performance instead of interval meter data. The rules do not require a specific sampling methodology, but instead allow the Market Participant to determine a methodology appropriate for its resources. Proposed Small Customer Aggregation methods using sampling must go through the NYISO stakeholder process and receive working group and committee chair and vice-chair approvals.[147] To date no sampling methodology has been approved for use in the NYISO, though there is one proposal currently working through the NYISO process. [148]

6.2 Sampling Method Basics[149]

Simple random sampling relies upon a single key assumption: there is homogeneity among each member of the population. A key parameter in determining sample size is the coefficient of variation which is used to gauge the consistency of the data with respect to the average (mean) in the data population. For any sample or distribution of data, the coefficient of variation is the standard deviation divided by the mean or $C.V. = \frac{\sigma}{\mu}$, where σ is the standard deviation and μ is the mean or average of the data. The C.V. is usually multiplied by 100 and expressed as a percentage, and is bounded below by zero.

The smaller the C.V., the more consistent the data with respect to the average and the assumption regarding homogeneity seems to be true. That is, the data observations are clustered closely around the average. The implication is that only a small sample from the population is needed to get a relatively precise measure of what is happening with the entire population. In the context of

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http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/edrp_mnl.pdf.

[147] *Id.*

[148] Joule Energy Services, *Small Customer Aggregation in CCAs*, November 30, 2017, presentation to the ICAP Working Group, available at http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2017-11-30/SCA%20Presentation_Committee%2011.22.2017.pdf .

[149] The math in this section follows closely the presentations of how sampling is used in ISO-NE and PJM. For example see PJM Interconnection, *PJM Manual 19:Load Forecasting and Analysis*, Revision: 32, Effective Date December 1, 2017, Attachment C, Residential Non-Interval Metered Guidelines available at http://pjm.com/-/media/documents/manuals/m19.ashx and ISO-NE, *ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR*, Revision: 6 Effective Date: June 1, 2014, Section 7, Statistical Significance, available at https://www.iso-ne.com/static-assets/documents/2017/02/mmvdr_measurement-and-verification-demand-reduction_rev6_20140601.pdf.

demand response, having like device sizes, such as the size of an HVAC unit, device types, and location can reduce the coefficient of variation. In this way, the size captures factors such as size of the house or location being cooled or heated, the type ensures similar performance and behavior, and the location should have similar weather conditions driving HVAC load. Of course, household preferences for the temperature at which the HVAC is set can drive differences in loads between otherwise like sites, and should be captured by the C.V.

Conversely, if the C.V is large, this means the data observations are far more dispersed away from the average. Using the HVAC context, a large C.V. may imply the population of sites and the sample have not been sufficiently stratified to group sites by like characteristics (device size, type or location) or it could mean the effect of unobserved characteristics such as temperature setting in the population is widely dispersed. The implication here is a relatively large sample from the population is needed to get a relatively precise measure of what is happening with the entire population.

Assuming a standard normal distribution, the Z-statistic provides a confidence interval given the relative precision or error that is acceptable. For a 90 percent one-tailed confidence interval or two tailed 80 percent confidence interval, the Z-statistic is 1.28. For greater accuracy such as a 90 percent two-tailed confidence interval, the Z-statistic is 1.645.

To determine the number of samples in an infinite population, n', that would achieve an acceptable error or relative precision, R.P., at a two-tailed confidence of 90 percent (Z-stat = 1.645), with a given C.V.

$$n' = \left(\frac{Z}{R.P.}\right)^2 C.V.^2 = \left(\frac{1.645}{R.P.}\right)^2 C.V.^2$$

The above equation assumes an infinite population. For finite samples with the number of observations, N, the required sample size is a function of the number of samples in the small population, N, and the numbers of samples that would be required in an infinite population, n'. As N approaches infinity, n = n'

$$n = \frac{n'}{1 + \frac{n'}{N}}$$

6.3 Sampling for Demand Response M&V in PJM and CAISO

The sampling methodology for demand response is the same in PJM and CAISO and utilizes a methodology requiring a two-tail precision of 90% (or 95% one tail).[150]

In PJM, if no C.V has been established for the population, or the population is heterogeneous, the default C.V.=1, and the PJM and CAISO methodology would require a sample of 271 sites for an infinite population of DR sites. For a small population, N=150, this would require a sample n=97.[151]

If a Market Participant does not wish to use the default C.V., or wants to update the C.V. for the population of sites in the aggregation, PJM allows for a variance study to be conducted with an initial sample population of at least 75 sites. CAISO in contrast assumes that the C.V.=1 to calculate the required sample size for the population of DR sites.[152]

Sampling can be used for participation in energy, capacity and synchronized reserve markets in PJM and C.V. studies can be done for each of these markets. To determine a C.V. for energy or capacity market participation, four consecutive weeks of hourly intervals (672 intervals) are required. A C.V. study for Synchronized Reserve participation requires 2 consecutive weeks of one-minute intervals (20,160 intervals).

[150] PJM Interconnection, *PJM Manual 19: Load Forecasting and Analysis*, Revision: 32, Effective Date December 1, 2017, Attachment C, Residential Non-Interval Metered Guidelines available at http://pjm.com/-/media/documents/manuals/m19.ashx and California ISO, *Demand Response User Guide*, May 5, 2017, Approved Statistical Sampling Methodology, p. 170-175, available at http://www.caiso.com/Documents/DemandResponseUserGuide.pdf. ISO-NE uses an 80 Percent precision for demand response and energy efficiency sampling *See* ISO-NE, *ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR*, Revision: 6 Effective Date: June 1, 2014, Section 7, Statistical Significance, available at https://www.iso-ne.com/static-assets/documents/2017/02/mmvdr_measurement-and-verification-demand-reduction_rev6_20140601.pdf. PJM also uses sampling for energy efficiency with the same precision as ISO-NE which PJM characterizes as a one-tailed 90 percent precision. *See* PJM Interconnection, *PJM Manual 18B:Energy Efficiency Measurement &Verification* Revision: 03 Effective Date: November 17, 2016, Section 9 Statistical Significance, available at http://pjm.com/-/media/documents/manuals/m18b.ashx.

[151] For DR and EE in ISO-NE and EE in PJM the sample sizes would need to be 164 for a C.V.=1 with an infinite population. In the case of a small population, N=150, the number of samples would be n=78.

[152] For example, in the *Demand Response Users Guide,* the CAISO provides a table with the number of PDR locations and the sample fraction. For 2000 sites, the sample fraction is 12% or 220 sites that must be interval metered.

In the CAISO market, sampling to settle non-interval metering customers is only permitted in the energy market. Reserve market participation requires some form of interval metering, but sampling of interval metering with intervals greater than 5 -or 15- minute granularity is permitted.

6.4 Observations and Recommendations

Statistical sampling methodologies are not a substitute for physical metering at each individual resource. However, for a certain subset of resources statistical sampling may provide a reasonable alternative when installing appropriate metering infrastructure is either not available or economically burdensome. At least with certain forms of direct load control (DLC) there is sufficient homogeneity in the measures to employ simple random sampling.

PJM and ISO-NE also acknowledge there is likely heterogeneity among sites in their manual documentation, and it is expected that with such heterogeneity, that sites will be stratified sufficiently such that each sample is relatively homogeneous in its make-up. The CAISO does not address this issue by assuming a default coefficient of variation of 1. Furthermore, with population sizes less than 200 sites, the need for interval metering for such a large subset of sites assuming a C.V.=1, requires 60 percent or more of the sites to be interval metered, it almost seems to make sense simply to interval meter every site in the end.

It is recommended the NYISO adopt established methods and guidelines for sampling to *facilitate the participation of small site demand response aggregations* with the limits and conditions as discussed below.

6.4.1 Recommendation: Statistical Sampling is not Suitable for Non-DR DER

It is important to note that statistical sampling in ISO/RTO markets is primarily related to mass market loads, and where there is homogeneity among those sites. However, DERs will have differences over a number of dimensions. For solar and wind DER there are differences in size and location. For wind, output can be affected by tower height and the prevailing weather patterns that may be location specific. For solar DER, the positioning of solar panels, ability to track the sun, and difference in solar radiance among location can make the output of solar DER be unique to each location.

Given the number of strata that would be required to get sufficient homogeneity in a sample, it would seem impractical and untenable to use sampling for any DER application, keeping in mind the minimum sample size for a C.V. study in PJM is 75 sites, which is still a relatively small sample. Moreover, going forward some DER is likely to be compensated for distribution services outside the NYISO wholesale market construct under the VDER tariff recently approved by the NYPSC, and would require some form of interval metering to be implemented to satisfy requirements under the VDER tariff rules.[153]

Finally, Behind-the-Meter Net Generation (BTM:NG) Resources that participate in the NYISO wholesale markets are required to have metering in place,[154] and the idea that DER could inject power into the system, requiring metering for DER would provide symmetric treatment along-side current BTM:NG Resources in NYISO.

In the end there is no substitute for metering of DER to get the most accurate information for settlements and for operations. This is already the case today as demand response is deployed locationally to account for transmission constraints. The integration of DER embedded in the distribution system, will only make the need for operational visibility that much greater.

6.4.2 Recommendation: Adopt a Default Sampling Method/Guidelines for Demand Response that Follows CAISO and PJM

Given that the NYISO already has the possibility of using sampling for demand response in its tariff, it would make sense to adopt the CAISO and PJM demand response standards to provide some uniformity with other ISO/RTO practices which allows market participants to take advantage of common rules across markets. However, there are some other changes that also go along with this overall recommendation as discussed below.

6.4.3 Streamlining the Approval Process for Statistically Sampled Aggregations

ISO/RTOs have the expertise and knowledge to develop appropriate sampling methods and statistical significance requirements for demand response participation in their markets. Once those methods have been reviewed and approved by stakeholders, statistically sampled aggregation proposals should require approval by ISO/RTO staff only. Neither PJM nor the CAISO require

[153] NY DPS, Case 15-E-0751, *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding* October 27, 2016, p. 26.
[154] NYISO, *Revenue Metering Requirements Manual,* December 2016, Section 3.2, available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Administrative/rev_mtr_req_mnl.pdf

stakeholder approval of proposals to use sampling methods. PJM staff review the proposals to use sampling methods and verify that the statistical requirements are met and that samples are stratified such that the populations and samples are sufficiently homogenous.[155]

In summary, the NYISO should predefine a common sampling methodology for participation of demand response in its markets, including guidelines for how proposals are to analyze homogeneity within the population and samples. Once the methodology has been approved by stakeholders, market participants should be able to apply those methodologies subject to NYISO oversight and approval.

6.4.4 Adopt a Standard for sites for a Coefficient of Variation Study with Stratified Samples

The NYISO should only allow a C.V. study for homogeneous samples of 75 or more sites. Given that larger populations of demand response resources can be separated (stratified) by device size, type and location as discussed above, a sample of 75 sites that have these same criteria would provide some confidence that there is sufficient homogeneity in responses among all sites with the same characteristics. Additionally, metering 75 sites up front would cover the number of sites required for metering if the study resulted in a coefficient of variation of 0.5 (C.V.=0.5) is used in the sample size calculation.

6.4.5 Default Coefficient of Variation is 1

Absent a good C.V. study and following PJM and CAISO the default coefficient of variation should equal 1 (C.V.=1). The sample required for metering would ensure a majority of the sites in the population would be interval metered. This seems to be a reasonable path forward for small populations of homogeneous characteristics (75 sites or fewer), or for larger population that would require stratification into smaller homogeneous samples until a C.V study can be done. This is a change that could be easily supported by NYISO staff in the short term with adoption of the statistical methods in place already in PJM and CAISO.

[155] ISO-NE also follows this process for both demand response and energy efficiency. CAISO does not outline the process for sample stratification in its documentation as PJM does.

6.4.6 Recommendation: Statistical Sampling for Ancillary Service Provision is Not Appropriate for the NYISO

First, no ISO/RTO surveyed in the study allows for statistical sampling for participation in the market for regulation and frequency response. The reasons are straightforward in that regulation service requires a resource to have the ability to accept and deliver basepoints and data on a six second basis, and requires appropriate real-time metering in order to precisely monitor in real-time what resources providing regulation are doing to help maintain system frequency.

ISO-NE is moving toward integrating demand response into the 5-minute dispatch and energy and ancillary service co-optimization algorithms which requires 5-minute interval metering such that they have operational visibility.[156]

The CAISO, in spite of allowing sampling, still requires interval metering of all demand response providing reserves, even for sampling purposes. The CAISO samples all sites with interval metering on a 5 or 15-minute basis, but the part of the population that is not sampled may only have hourly interval meters, but otherwise have like characteristics.

While PJM allows sampling of non-interval metered customers to be done for the provision of synchronized reserves, PJM is a large system, nearly eight times the size of the NYISO, but with very similar reserve requirements in total MW.[157] Sampling in PJM, even with ten percent error, would not be a large enough to be distinguished from other variations in a large system. Just for the purposes of a numerical example, if all synchronized reserve were held in the form of demand response in PJM, then a 10 percent error could be 130 MW on a system with an average load of approximately 88,601 MW in 2016 is only 0.15 percent of load.[158]

NYISO, in contrast being a smaller system, a ten percent error in response would have much greater impacts on the system since the amount of reserves being held on a MW basis are comparable. A 130 MW error in NYISO, which has an average hourly load of 18,306 MW in 2016

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[156] ISO New England and New England Power Pool, Docket No. ER17-2164-000, *Revisions to Implement Full Integration of Demand Response* (Jul. 27, 2017).

[157] PJM maintains Synchronized Reserve that can respond in 10 minutes or less to meet the largest contingency which is no more than 1300 MW, and Non-Synchronized Reserve that can respond in 10 minutes or less that is 50% of the largest contingency.

[158] Monitoring Analytics, LLC. *2016 State of the Market Report for PJM,* March 9, 2017. Section 3, p. 93. Available at http://monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec3.pdf.

is 0.71 percent of load[159] (5 times the PJM figure) and this has a much greater impact on frequency and area control error (ACE). Given the size of the NYISO system, sampling is not precise enough to ensure the reserves being counted upon are actually being delivered to arrest a frequency drop associated with a contingency such as the loss of a large generator. Operators need to know that the reserves available will deliver energy when needed.

[159] NYISO, *2017 Load & Capacity Data: "Gold Book"*, Table I-4a, available at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2017_Load_and_Capacity_Data_Report.pdf.