COMPARING ISO LOAD FORECASTING METHODOLOGIES

Factoring Behind the Meter Generation into the Demand Forecast Algorithm

RELIABLE ENERGY ANALYTICS LLC

http://reliableenergyanalytics.com
Email: dick@reliableenergyanalytics.com

Executive Summary

This report aims to achieve the following objectives:

- Describe the current methodologies[1] used by two ISO's (ISO New England and the New York ISO[2]) to "factor in" the "yin-yang effect" of Behind the Meter (BTM) Photovoltaic (PV) supply resources in load forecasting
- Stimulate industry discussion on the need for an industry wide standard methodology for load forecasting that consistently incorporates the impact of BTM PV and establishes agreed semantics and business practices
- Differentiate the "old concept" of Peak Demand, "maximum electric power consumption of all consumers at a given moment in time" and the newly introduced "Peak Power from Grid Resources" (PPGR), peak demand concept, which represents the maximum amount of supply expected from grid resources
- Introduce the need for an "Estimated Peak Ramp Rate" (EPRR) as a risk factor representing the rate at which the loss/addition of Solar supply can impact demand and the corresponding requirement on Grid Resources ramping response (both increase and decrease) over a defined period (perhaps 5 minute grain) to maintain balance and system frequency

Forecasting hourly peak power demand has always been a bit of a guessing game, mostly driven by weather and climate conditions. A 2% margin of error was not uncommon when comparing forecast to actual electricity demand. But what does it really mean when an ISO publishes a load forecast with a "Peak Demand" (a/k/a Peak Load) number in this era of Distributed Energy Resources (DER) - does this number represent the maximum consumption of electric power by consumers within a load area or service territory at a given moment in time?

As behind the meter generation reaches critical mass, and continues to grow, the peak demand "concept" has morphed into something semantically closer to "Peak Power from Grid Resources" (PPGR), as opposed to the forecasted peak power consumption of all consumers of electricity in a geographical area. A growing amount of consumer electricity demand is being met by behind the meter (BTM) supply resources, such as Photovoltaic Solar Panels (PV), reducing the need for grid supplied power, as evidenced by "dropping peak demand" in ISO forecasts across America.

Consumer electricity consumption is not decreasing, as one might infer from the drop in ISO forecasted peak demand, but is, in fact, expected to increase [15]. Experts from the IEA [17] assert that deep electrification will drive increased demand, "Laura Cozzi, head of the IEA's

[1]This report makes no judgment as to the quality/correctness of the load forecasting methodologies used by ISO New England and the New York ISO. Their inclusion in this report is simply to demonstrate the different approaches used by each ISO and the need for a standard methodology, and semantics, to ensure consistency in load forecasting across North America.

[2] These two ISO's were selected for this research due to their consistent regulatory and compliance requirements within the NPCC power region. This ensures that both entities are subjected to the same reliability rules.

Energy Demand Outlook Division, said: “We are seeing growing electrification happening throughout the energy sector – electricity going into sectors that were confined to other fuels before: most notably, cars, but also heating and cooling.””. Simultaneously, Non-Wires Alternatives[3] [16], intended to forego additional investments in transmission and distribution, along with the expansion of energy efficiency measures [29] and renewable DER deployments [30], especially BTM PV generation, are advancing and will surely meet some portion of this increased consumer demand.

The 2018 NERC Reliability report [18] concisely captures the current state: “*The electricity sector is undergoing significant and rapid change, presenting new challenges and opportunities for reliability*”. Powerful forces are moving at a rapid pace, presenting the ISO’s with a very difficult challenge; how to accurately forecast the amount of “Peak Power from Grid Resources” (PPGR) to meet hourly consumer demand, and plan for future supply capacity to meet an evolving and highly volatile load curve, in a changing and uncertain future for the energy industry. The potential speed of this energy transition may best be expressed in the following graphic of New York City, depicting the rapid adoption of the automobile over 13 years:

Easter morning 1900: 5th Ave, New York City. Spot the automobile.

Source: US National Archives.

Easter morning 1913: 5th Ave, New York City. Spot the horse.

Source: George Grantham Bain Collection.

This report documents research into the various methods used by ISO's to compute "peak demand" as part of their load forecasting function. The NYSIO clearly states the importance of this “peak demand” value, [32] *“peak demand is an important metric because it defines the amount of energy producing resources, or power capacity that must be available to serve customers’ maximum demand for energy to avoid disruptions to service”*

[3] Non-wires alternatives are defined as “an electricity grid investment or project that uses non-traditional transmission and distribution (T&D) solutions, such as distributed generation (DG), energy storage, energy efficiency (EE), demand response (DR), and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level,”

The aim of this report is to demonstrate the lack of consistency across ISO's in the meaning and calculation of the forecasted "peak load" (a/k/a "peak demand") and to show the need for a consistent, standard methodology to eliminate these differences.

Equally important is the need to make clear the difference between the "old peak demand" concept and the new PPGR concept of peak demand, especially with regard to the need for a standard algorithm to calculate the PPGR value. The report also introduces the "yin-yang effect of BTM PV: whatever BTM PV supply does not get produced (i.e. due to weather), will likely result in an increase in demand/load approximately equal to the "missing BTM supply". This characteristic is unique to BTM PV supply as opposed to other PV Supplies, i.e. large solar farms, which purely generate power and do not mask "hidden demand".

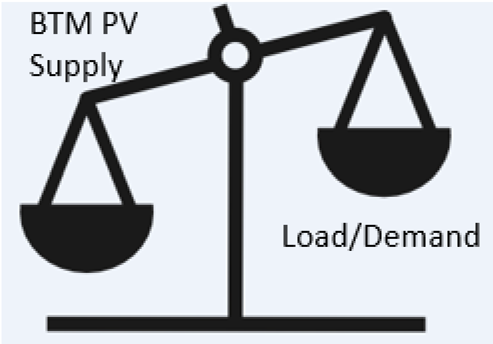


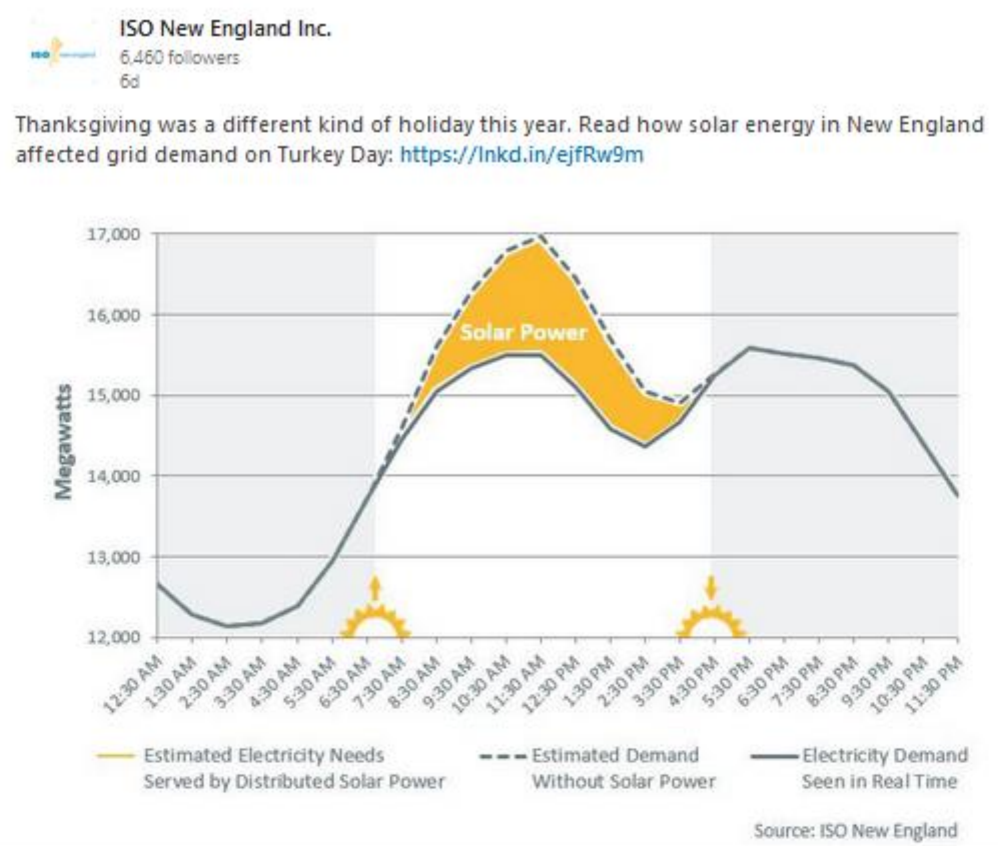
Figure 1. Yin-Yang effect of BTM PV Supply on Demand

An additional concept is also introduced, "Estimated Peak Ramp Rate" (EPRR), addressing the need for both up and down ramping capabilities over a specified period of time, perhaps every 5 minutes. EPRR serves as a risk factor to consider when forecasting PPGR "peak demand" and the planning of Grid Resources and Ancillary Services, such as operating reserves and regulation. The California ISO appears to working on a concept similar to EPRR, to address the need for rapid ramping capabilities [21], referred to as "Three-Hour Net load Ramp".

Introduction

Forecasting peak electricity demand has always been rather difficult to predict with 100% accuracy, as the great Yogi Berra so eloquently pointed out, "*It's tough to make predictions, especially about the future*". But this challenge is becoming even more difficult for those with the responsibility to plan each days/hours balancing act of matching electricity supply with demand, namely the Independent System Operators and other NERC Balancing Authorities.

The inspiration for the research described in this report was provided by a post from ISO New England containing the following graphic:



This prompted the question; how does an ISO determine the "Estimated Demand", depicted in the graphic above as a dashed line, in this world of rapidly expanding, intermittent, behind the meter (BTM) generation. This report documents the findings of this research and a few observations to consider that may provide a framework for standardizing the methods used by ISO's and BA's to forecast "daily peak demand" expressed as the amount of "Peak Power from Grid Resources" (PPGR) that will be needed to meet consumer demand, not met by variable output, BTM resources.

Purpose of the Load Forecast and Peak Demand

In order to understand the purpose of forecasting peak demand in a load forecast one must consider the role of a "Balancing Authority" in the NERC Functional Model [1]. NERC describes the Balancing Authority as*, "The functional entity that integrates resource plans ahead of time, maintains generation load-interchange-balance within a Balancing Authority Area, and contributes to Interconnection frequency in real time".* Number 5 in the list of responsibilities is the requirement *to "Compiles load forecasts from Load-Serving Entities".*

A load forecast can cover a wide range of time periods from minutes to years. Each forecast is subject to a certain degree of uncertainty which tends to become less accurate for the longer time periods. For example, peak demand forecasts for the next 15 minutes are typically more accurate than the 7 days load forecast. Many factors must be considered when constructing a load forecast, including historical usage patterns, climate, weather, weekday, weekend, significant societal events, i.e. the Super Bowl, economic growth, type of loads being served within an area, i.e. Commercial, Industrial, Agricultural, Residential, etc., and the impact of behind the meter generation and storage technologies, to name a few.

ISO's have been refining their forecasting methodologies over the years and had reached a point where day ahead forecasts were within 1% of actual peak demand, on many days. ISO's need the forecasted "peak demand" to be a close approximation of actual demand in order to determine the number of generators to "start-up" (commit) to reliably meet the anticipated demand, and maintain system balance. Errors in forecasting peak demand can have both reliability and economic consequences. With the rapid adoption of behind the meter generation, energy efficiency measures and storage technologies it has become much more difficult for ISO's to accurately predict the hourly impact on demand due to the intermittent behavior of DER, especially BTM PV resources, as noted in NERC's 2018 Reliability report[4] [18].

There was a time, not too long ago, when peak demand was synonymous with "peak electricity consumption at a moment in time", usually expressed in Megawatts (MW), i.e. the all-time peak demand recorded in ISO New England's Balancing Area occurred on August 2nd, 2006 at 28,130 MW [2]. This peak demand number has steadily declined since 2006 and stood at 23,968 MW in 2017, according to ISO-NE published materials [3]. The reason for these reductions in peak demand have been documented by ISO New England "EE and solar PV are reducing demand growth. State-sponsored energy-efficiency and behind-the-meter solar PV resources are slowing the growth rate for summer peak demand and flattening overall electricity demand for the 7.1 million retail electricity customers in New England." [4].

Which brings us to the question, what exactly is "peak demand", now that it no longer appears to represent "peak electricity consumption at a moment in time"? The concept seems to be morphing into something a little closer to "the peak amount of Grid supplied power needed to

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[4] "In March 2018, **CAISO set a new ramping record with actual three hour upward net-load ramps reaching 14,777 MW**. The maximum **one hour net-load upward ramp was 7,545 MW**."

balance supply/demand and maintain system frequency, after factoring in the yin-yang effect of BTM PV and other supply resources".

This research attempts provides some insight as to the different methods used by two ISO's, ISO New England and the New York ISO, in constructing their load forecast peak demand values. No judgement is made as to the quality or correctness of these methodologies. Their presence in this report is to highlight the need for a standard load forecasting methodology for North American ISO's and Balancing Authorities. Recommendations are proposed to offer some thoughts as to the development of a standard methodology for calculating peak demand as it evolves from "peak consumer consumption" into "Peak Power from Grid Resources" (PPGR), if such a standard should ever come to fruition.

ISO Peak Demand Forecasting Methodologies

NERC/NPCC STANDARDS

Both ISO New England and the New York ISO operate within the Northeast Power Coordinating Council (NPCC) region, which establishes a baseline set of standards and guidelines for operating the electric grid reliably. These standards and guidelines receive federal level support from the North American Electric Reliability Corporation (NERC). NERC has enforcement authority over the nations Balancing Authorities (BA) and can/have imposed some significant fines for non-compliance of these standards.

NERC's Reliability standards [7] contain prescriptive, enforceable requirements describing functions that BA's must implement, or face non-compliance penalties. NERC standard MOD-031-2, Demand and Energy Data, is intended to ensure that functional entities, especially BA's, have the information required to support reliability studies and assessments. Section B, R1. 1.3 through 1.5, specifically calls out the data requirements which a BA should have access to. NERC provides some guidance [20] on the data needed to model DER resources, but it's unclear if this set of parameters is sufficient to assess the yin-yang effect of BTM PV resources and the impact on PPGR forecasts.

These BTM PV resources can represent a significant amount of power [18], given the momentum behind rooftop solar, wind and battery resources. These supply resources are being implemented outside of the ISO's peripheral vision, leaving each BA/ISO to decide for themselves how best to "factor in" these BTM PV generation resources into their methodology for calculating peak demand. It should be noted; NERC is aware of the real potential of distributed energy resources to affect peak load, as noted in [8], "*Distributed energy resources (DERs) are accounted for in area load profiles and reflect in peak load projections. Growth in DERs could result in actual year 2022 peak load requirements that are lower than projected in the scenario*". In March 2018, the CAISO reported a record breaking one-hour upward demand swing of 7,545 MW. This record coincided with utility-scale PV serving nearly 50 percent of the CAISO demand during the same time period [18]. The BTM PV impact affecting this demand swing was not reported.

The BTM PV supply number is important due to its unique reciprocal relationship on supply/demand. Whatever amount of BTM PV MW does not become supply, will likely become demand. For example, if 100 MW of BTM supply becomes impacted by foggy conditions that reduce solar radiance, resulting in a supply reduction equal to 50 MW, the "missing supply" of 50 MW becomes an increase in load/demand of 50 MW. The consumer demand for electricity doesn't go away when the sun goes away, and this "yin-yang effect" needs to be incorporated into the forecasting of peak demand MW.

Several factors, in addition to the DER data identified by NERC [20], can influence the forecasted peak demand value on an hourly/daily basis, pertaining to BTM PV resources. These factors include:

- Location of BTM resources
- Weather at location of BTM resources
- Normative demand by location, exclusive of DER
- Capacity of BTM resources, by location
- Capacity Factor – how much power can be expected from the BTM resources
- Yin-yang effect of BTM, on a locational basis – is the supply/demand effect reliably reciprocal and predictable
- Presence of battery technologies combined with BTM resources
- Presence of other generating capabilities in addition to PV, such as Wind or CHP generation at a given location.
- Discount factors and assigned weights and other ISO specific factors used in the load forecast process

Given the lack of a standardized model for calculating the effects of BTM PV on supply/demand, and the lack of visibility into these BTM resources and the inability to control these resources, ISO's, have had to fill this vacuum by constructing their own algorithms to estimate the impact of BTM PV on peak demand and the amount of Grid supplied generation resources (PPGR) needed to meet reliability requirements.

ISO NEW ENGLAND LOAD FORECASTING METHODOLOGY

The primary sources of information regarding ISO New England's peak demand forecasting methodology were provided by [9][10] and [11]. Some additional data on behind the meter supplies was obtained during a Distributed Generation Forecast Working Group (DGFWG) meeting hosted by ISO New England on 12/10/2018 and 2019 estimates of peak demand forecasts obtained during an ISO New England Load Forecasting meeting held 12/14/2018.

Generators across New England are committed to provide electrical energy on a day ahead basis using Reserve Adequacy Analysis (RAA) and Security Constrained Reliability Analysis (SCRA) studies. One of the most critical, key parameters used in making these day-ahead "commitment decisions" is the amount of forecasted hourly demand, with the daily forecasted hourly "peak demand" serving as a high-water mark for generation supply needed to meet the "maximum power demand" scenario, on a given hour/day.

A demand forecast is developed using a combination of hourly temperature, dew point, wind speed and direction, cloud cover, and precipitation
for 8 New England cities for the current day and next six days. Three different modeling tools are used to forecast demand, along with historical data of similar days, with the results being consolidated using a weighted algorithm. The assignment of weights is subjective and is determined by each load forecaster that is responsible for producing a load forecast [9].

The seven-day load forecast contains projections of future energy demand and provides a high-level overview of available capacity to meet the forecasted demand, as shown in figure 1:

WEATHER	DAY 2 THU 09/06	DAY 3 FRI 09/07	DAY 4 SAT 09/08	DAY 5 SUN 09/09	DAY 6 MON 09/10	DAY 7 TUE 09/11
High Temperature - Boston	92	75	68	66	68	77
Dew Point - Boston	70	63	53	46	60	70
High Temperature - Hartford	90	78	73	69	70	80
Dew Point - Hartford	73	57	50	46	55	70
GENERATING CAPACITY POSITION						
Total Capacity Supply Obligation (CSO)	30,239	30,239	30,239	30,239	30,239	30,239
Anticipated Cold Weather Outages	0	0	0	0	0	0
Other Generation Outages	1,898	1,839	2,759	2,862	3,076	2,932
Anticipated De-List MW Offered	791	791	791	791	791	791
Total Generation Available	29,132	29,191	28,271	28,168	27,954	28,098
Import at Time of Peak	2,755	2,755	3,095	3,095	3,295	3,295
Total Available Generation and Imports	31,887	31,946	31,366	31,263	31,249	31,393
Projected Peak Load	23,200	16,860	13,730	13,600	15,210	17,830
Replacement Reserve Requirement	160	160	160	160	160	160
Required Reserve	2,303	2,303	2,303	2,303	2,303	2,303

	DAY 2 THU 09/06	DAY 3 FRI 09/07	DAY 4 SAT 09/08	DAY 5 SUN 09/09	DAY 6 MON 09/10	DAY 7 TUE 09/11
Required Reserve including Replacement	2,463	2,463	2,463	2,463	2,463	2,463
Total Load plus Required Reserve	25,663	19,323	16,193	16,063	17,673	20,293
Projected Surplus or Deficiency	6,224	12,623	15,173	15,200	13,576	11,100
Available Real-Time Demand Response	327	327	327	327	327	327
LOAD RELIEF ACTIONS ANTICIPATED						
Power Watch	N	N	N	N	N	N
Power Warning	N	N	N	N	N	N
Cold Weather Watch	N	N	N	N	N	N
Cold Weather Warning	N	N	N	N	N	N
Cold Weather Event	N	N	N	N	N	N
Energy Emergency	N	N	N	N	N	N

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Figure 2 ISO NE Seven Day Load Forecast Example

In developing the "Projected Peak Load" number shown in figure 1, ISONE considers, among other things, the amount of BTM PV supply [10] within New England. The BTM PV supply number is important due to its unique reciprocal relationship on supply/demand, referred to in this document as "the yin-yang effect". Whatever amount of BTM MW does not become supply, will likely become demand. For example, if 100 MW of BTM supply becomes impacted by foggy conditions that reduce solar radiance, resulting in a supply reduction equal to 50 MW, the "missing supply" of 50 MW becomes an increase in load/demand of 50 MW. The consumer demand for electricity doesn't go away when the sun goes away and this yin-yang effect on BTM resources needs to be incorporated into the forecasting of peak demand (a/k/a peak load).

ISONE METHODOLOGY FOR CALCULATING BTM PV SUPPLY/DEMAND IMPACT

The materials presented in the remainder of this section were obtained from [9][10] and [11].

Figures 2 and 3, below, appear to indicate that BTM PV resources located throughout New England are forecasted to reduce Summer 2018 (July 1st) peak load, when electricity demand is typically high, by 632.6 MW, which was calculated using the methodology described in [11]. However, an analysis of BTM Nameplate MW's indicate the "potential" power generation capacity of these BTM resources to be 1,820.2 MW's. The difference between the "forecasted peak load reduction from BTM" (632.6), as calculated, and "BTM nameplate MW" (1,820.2) equates to 1,187.6 MW of BTM nameplate capacity that was not considered in the reduction to peak load MW, but, theoretically, could add to overall supply MW.

BTM PV: July 1st Estimated Summer Peak Load Reductions

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Behind-the-Meter PV	CT	125.6	154.5	181.6	207.1	229.2	246.2	258.9	266.5	273.4	280.3	286.1
	MA	291.4	315.7	356.4	383.8	408.0	429.0	448.0	465.3	477.2	482.5	486.5
	ME	12.0	14.6	17.9	21.0	23.7	26.2	28.4	30.5	32.5	34.4	36.3
	NH	22.8	26.4	30.0	33.5	36.6	39.3	41.8	44.1	46.2	48.4	50.5
	RI	8.8	16.4	23.1	29.1	34.2	38.6	42.8	46.6	50.2	53.8	57.1
	VT	86.7	105.1	111.6	115.7	119.2	122.2	124.8	127.1	129.4	132.0	134.3
Total	Cumulative	547.2	632.6	720.6	790.2	850.9	901.5	944.8	980.1	1008.9	1031.4	1050.7

Notes:

(1) Forecast values are for behind-the-meter PV resources only
(2) Values include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day
(3) Values include the effects of an assumed 0.5%/year PV panel degradation rate
(4) All values represent anticipated July 1st installed PV, and are grossed up by 8% to reflect avoided transmission and distribution losses
(5) Different planning studies may use values different that these estimated peak load reductions based on the intent of the study

Figure 3. 2018 Forecasted PV Reduction in Peak Load [10]

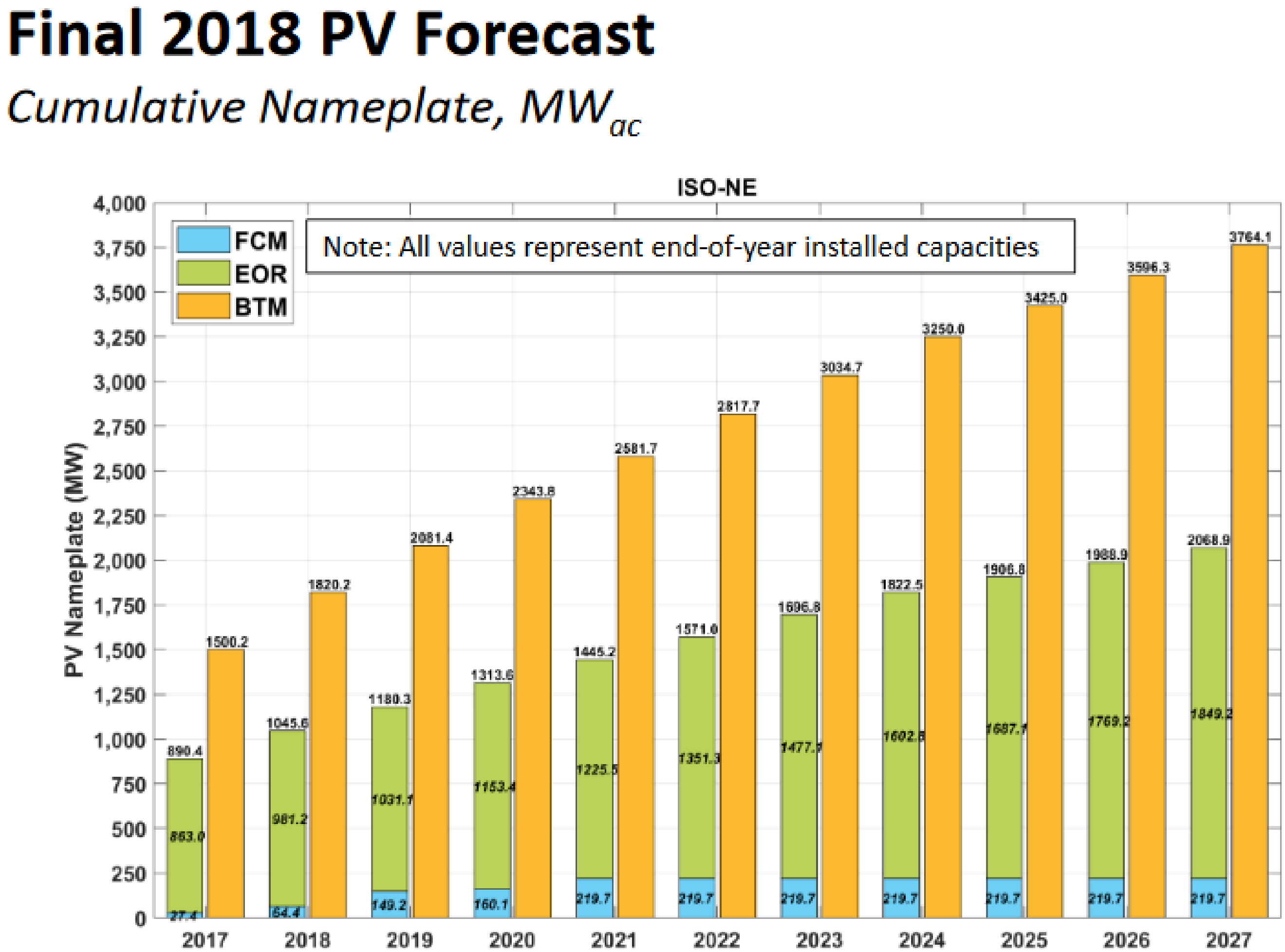


Figure 4. 2018 PV Resources Nameplate MW [10]

DETAILS OF ISO NEW ENGLAND BTM PEAK LOAD REDUCTION CALCULATION

ISO New England provides a detailed description of the methodology used to forecast peak load reduction MW, attributable to Behind the Meter PV resources, as shown in [11], with an example calculation provided in Appendix [10]. The example is used to describe the calculation used by ISO New England, shown below:

Variable	Calculation Line Item	Relevant Region	
NPV_T	*July 2018 Total Nameplate PV Forecast (MW)*	ISO-NE	2570.3
NPV_{BTM}	*July 2018 BTM PV Nameplate Forecast (MW)*	MA	809.5
PF	*% of Nameplate (from previous slide)*	ISO-NE	0.3663
D	*Panel Degradation Multiplier*	MA	0.9858
GF	*Peak Gross Up Factor*	ISO-NE	1.08
	Final BTM PV Summer Peak Load Reduction (MW)	MA	315.7

Final estimated peak load reduction calculated by multiplying all values highlighted in yellow

Figure 5. Example Calculation to determine Final BTM Peak Load Reduction

Variable Name	Description	Source
NPV_T	Region Wide Nameplate total of all PV resources forecasted to be available in a given month	Sum of State PUC forecasts with adjustments made by ISONE reflecting monthly values
NPV_{BTM}	State portion of region wide nameplate resources that are categorized as Behind the Meter (BTM) PV supply	State PUC [14] with adjustments made by ISONE reflecting monthly values
PF	A performance factor used to determine the amount of capacity provided by BTM PV	ISONE developed formula [11]
D	A degradation factor that estimates the percentage reduction of supply from BTM resources due to aging of generation equipment, i.e. PV panels. Assumed annual degradation rate (ADR) = 0.5% per year	ISONE developed formula [11]
GF	A static value (8%) provided by ISO New England representing T&D losses	ISONE developed formula [11]
Final BTM PV Value	The forecasted amount of reduction in peak load resulting from the production of BTM PV solar generating resources in a particular geographic area (in MA for the example)	Result of calculation

The "Final BTM PV Value", described above, represents the *anticipated* reduction of load during a peak hourly demand scenario. This number represents a best-case condition, based on the forecasting methodology used, exclusive of the effect of weather and other factors that can impact the actual BTM PV Value on any given hour. This value is subject to the yin-yang effect described elsewhere in this document; whatever BTM PV supply does not get produced (i.e. due to weather), will likely result in an increase in demand/load approximately equal to the "missing supply". The following graphic shows the effect on peak demand, based on the percentage of PV supply produced; as BTM PV supply decreases, the need for Grid supplied energy increases, depicted in the load forecast as "Peak Demand".

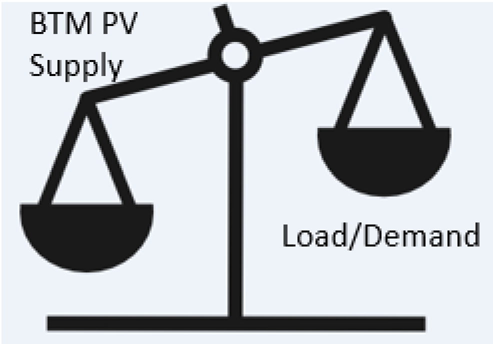


Figure 6. Yin-Yang effect of BTM PV Supply on Demand

No attempt is made to ascertain the accuracy or quality of this methodology. The intent of this report is to highlight the various methodologies used by ISO's to produce the forecasted peak demand, with particular attention to the method used to determine the impact of BTM PV supply resources on peak demand, as justification for the need of an industry standard methodology.

NEW YORK ISO LOAD FORECASTING METHODOLOGY

The information contained in this section was produced from the publicly available[5] information provided by the NYISO and other sources. Two NYISO methods of Load Forecasting were considered during the research conducted for this report, ICAP [13] and Day Ahead [24]. A third source, the 2018 Load and Capacity Data (Gold Book) [27] also provided valuable insights into the treatment of behind the meter supply in NYISO's load forecasting methodologies.

The ICAP Load Forecasting methodology utilized by NYISO, as specified in Manual 6 [12], was published in 2013. The published version does not describe the specific process used to determine the effect of BTM PV supply resources, covered in this report, to determine peak demand, however a draft 2018 (August 2018) version of Manual 6 [13] does contain some guidance on the treatment of behind the meter generation, referred to as BTM:NG. Although the draft version is not the "published" version of the load forecasting methodology used by NYSIO for determining the impact of BTM on peak load, this document [13] was used during this analysis, as it is the best available information at the time of writing.

Also, noteworthy, NYISO is subject to both NPCC [5] and NERC [7] requirements, the same as ISO New England, however it is also required to comply with New York State Reliability Council (NYSRC) Reliability Rules [25]. No equivalent to NYSRC could be identified for the ISO New England Control Area.

[5] "Publicly available" refers to the NYISO information which does not require a Digital Certificate for access to the material. Some "public data", i.e. DSS data, is protected by access control that requires an EIR Entity Code and Digital Certificate. No attempt was made to register in the EIR and acquire a digital certificate, i.e. as a market participant would, in order to gain access to the DSS data.

ANALYSIS OF NEW YORK ISO LOAD FORECASTING METHODOLOGY TO DETERMINE BTM PV IMPACT ON PEAK DEMAND

ICAP LF Methodology [13][25]

NYISO manages a program for "Behind-the-Meter: Net Generation" (BTM:NG), that is separate and distinct from the BTM PV resources covered in this report. These BTM:NG are dispatchable resources with a minimum nameplate rating of 2 MW and a minimum net injection to the NYS Transmission System or distribution system of 1 MW [13]. Manual 11, does indicate the impact of BTM:NG on peak demand, "*BTM:NG Resource Load is not considered in the calculation of the ICAP Market forecast because the Resource is required to satisfy all of its Host Load, and therefore contributes 0 MW to the Load at the time of the NYCA Peak."*

Manual 11 contains no specific guidance as to the method used to factor in the effects of BTM PV when forecasting peak demand, which is the focus of this report.

Section I, MODELING AND DATA, of the (NYSRC) Reliability Rules [25] contains specific requirements/rules which NYISO is expected to comply, with regard to Load Forecasting. These rules, especially section I.3, Load Forecasting, are to be applied, in addition to NERC [7] and NPCC [5] requirements, and have a direct influence on the load forecasting methodology employed by NYISO. Section I.3 makes no mention as to the handling of BTM PV supply as part of ICAP load forecasting, but instead requires NYISO to maintain documentation describing "*the scope and details of the actual and forecast (a) demand data* " (I.3.R1) and to report both Annual peak hour <u>actual</u> demands in MW (I.3.R2.1) and Annual peak hour <u>forecast</u> demands in MW (summer and winter) (I.3.R2.2). It's assumed NYISO includes the impact of BTM PV supply as part of its demand data determination for ICAP. This assumption is confirmed by information contained in [27], which states "*The baseline forecasts, which report the expected NYCA load, include the impacts of energy efficiency programs, building codes and standards, distributed energy resources, <u>and behind-the-meter solar photovoltaic power (solar PV)</u>.*"

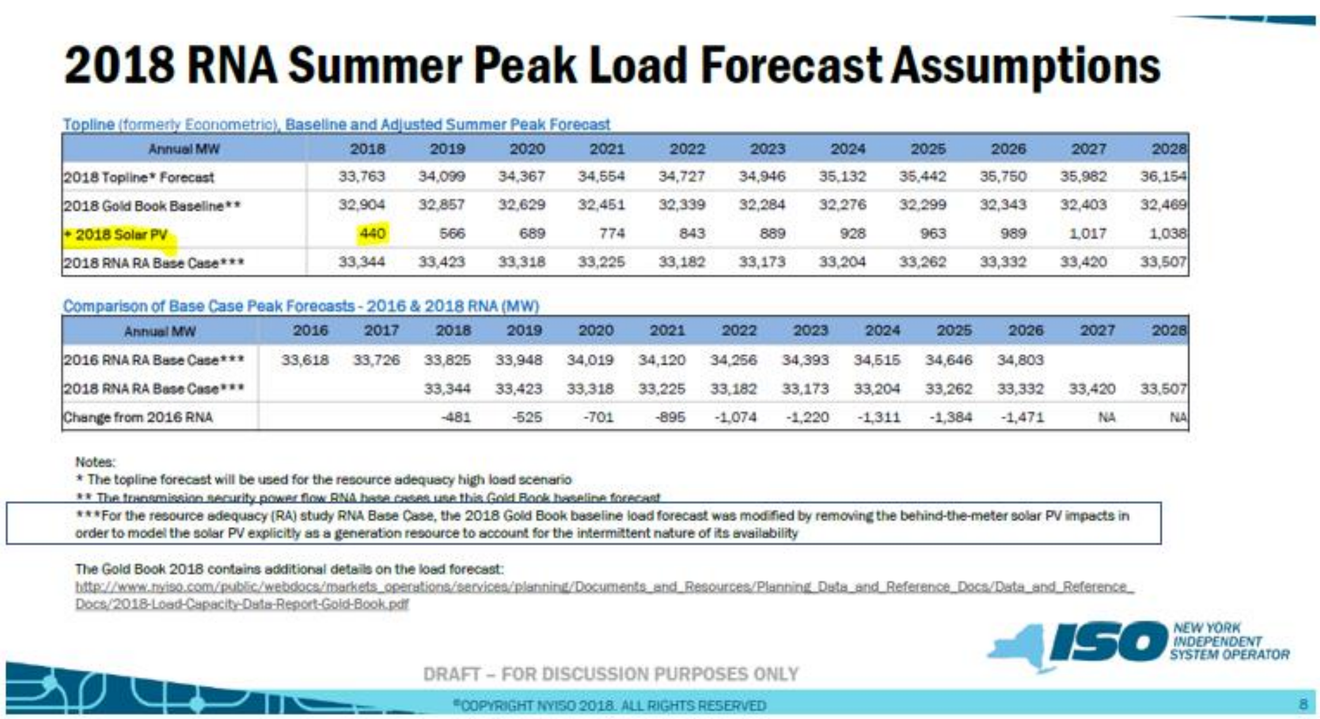
DA LF Methodology [24]

The load forecasting methodology described in [24] is used to forecast hourly loads for each of the eleven NY Control Area Zones and at the statewide level for the current day and the next six days. This Load Forecast function uses a combination of advanced neural network and regression type forecast models to generate its forecasts. The function uses historical load and weather data information (including temperature, dew point, cloud cover and wind speed) for each Zone to develop Zone load forecast models. These models are then used together with Zone weather forecasts to develop a Zone load forecast.

There is one load forecast model for each day of the week and each weather-defined season. There are no specific references as to the handling of, or potential impact from, BTM PV supply within section 6 "NYISO LOAD FORECAST PROCESS" [24].

Gold Book Insights [27] [28]

Neither of the load forecasting methodologies analyzed above (ICAP and DA) contained specific algorithms as to the impact/influence of BTM PV supply resources (covered by this report), on peak demand calculations. However, there is evidence that these BTM PV resources are being considered by NYISO. The "2018 RNA Final Results" presentation [28] contains a footnote describing the modeling of BTM PV in planning studies, as shown in the footnote (***) below:



2018 RNA Summer Peak Load Forecast Assumptions

Topline (formerly Econometric), Baseline and Adjusted Summer Peak Forecast

Annual MW	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2018 Topline* Forecast	33,763	34,099	34,367	34,554	34,727	34,946	35,132	35,442	35,750	35,982	36,154
2018 Gold Book Baseline**	32,904	32,857	32,629	32,451	32,339	32,284	32,276	32,299	32,343	32,403	32,469
+ 2018 Solar PV	440	566	689	774	843	889	928	963	989	1,017	1,038
2018 RNA RA Base Case***	33,344	33,423	33,318	33,225	33,182	33,173	33,204	33,262	33,332	33,420	33,507

Comparison of Base Case Peak Forecasts - 2016 & 2018 RNA (MW)

Annual MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2016 RNA RA Base Case***	33,618	33,726	33,825	33,948	34,019	34,120	34,256	34,393	34,515	34,646	34,803		
2018 RNA RA Base Case***			33,344	33,423	33,318	33,225	33,182	33,173	33,204	33,262	33,332	33,420	33,507
Change from 2016 RNA			-481	-525	-701	-895	-1,074	-1,220	-1,311	-1,384	-1,471	NA	NA

Notes:
* The topline forecast will be used for the resource adequacy high load scenario
** The transmission security power flow RNA base cases use this Gold Book baseline forecast
***For the resource adequacy (RA) study RNA Base Case, the 2018 Gold Book baseline load forecast was modified by removing the behind-the-meter solar PV impacts in order to model the solar PV explicitly as a generation resource to account for the intermittent nature of its availability

The Gold Book 2018 contains additional details on the load forecast:
http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2018-Load-Capacity-Data-Report-Gold-Book.pdf

The Gold Book [27] contained the most detailed information describing the methodology used by NYISO to determine the impact of "hidden" BTM supply resources on the peak demand forecast. Baseline and topline forecasts are described as follows:

Baseline Forecast	The expected NYCA load, include the impacts of energy efficiency programs, building codes and standards, distributed energy resources, and behind-the-meter solar photovoltaic power (solar PV)
Topline Forecast	shows what the expected NYCA load would be if not for these impacts [factored into the baseline forecast]

The incremental impacts of behind-the-meter solar PV and distributed generation are deducted from the forecast to produce the Baseline Forecast. The figure below taken from page 28 of [27] indicates that 1,504 MW (DC) of behind the meter PV was installed in the NY Control Area in 2018, broken down by zone:

Table I-9a: Solar PV Installed Capacity, Behind-the-Meter

Reflects Total Cumulative Installed Capacity

Installed Capacity by Zone - MW DC

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2008	0	0	1	0	0	2	3	0	0	1	10	17
2009	1	0	1	0	1	3	4	1	1	2	15	29
2010	4	1	2	0	2	5	7	1	2	3	26	53
2011	6	1	4	0	2	9	9	1	2	7	38	79
2012	9	2	7	1	4	16	14	2	3	14	50	122
2013	14	3	14	1	7	34	25	3	7	23	68	199
2014	18	9	23	1	12	54	44	8	11	40	104	324
2015	27	17	40	2	25	80	80	13	17	61	176	538
2016	38	23	63	2	38	127	119	18	23	88	246	785
2017	55	32	92	3	59	168	152	22	31	128	285	1,027
2018	82	62	144	9	88	202	255	27	40	181	414	1,504
2019	110	90	201	14	121	242	339	32	49	229	521	1,948
2020	142	118	264	20	157	278	415	36	57	272	602	2,361
2021	168	136	311	24	184	303	477	39	62	306	655	2,665

These 1,504 MW of BTM PV resources are anticipated to reduce coincident summer peak demand in 2018 by 440 MW (AC), as shown below:

Reductions in Coincident Summer Peak Demand by Zone - MW AC

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2018	23	17	41	3	25	58	75	8	12	54	124	440
2019	30	25	57	4	34	69	99	10	15	68	155	566
2020	39	33	75	6	45	80	122	11	17	81	180	689
2021	46	38	88	7	52	87	140	12	18	91	195	774
2022	52	42	99	8	58	93	155	12	20	100	204	843
2023	56	45	106	9	62	98	167	13	21	107	205	889
2024	60	47	113	9	66	102	178	13	22	112	206	928
2025	63	50	118	10	69	106	186	14	23	117	207	963
2026	65	51	122	10	72	108	194	14	23	121	209	989
2027	68	53	126	11	74	111	201	15	24	124	210	1,017
2028	70	54	130	11	76	113	207	15	24	127	211	1,038
2029	73	56	133	11	78	116	212	15	25	129	212	1,060
2030	75	57	137	12	80	118	216	16	26	132	213	1,082
2031	77	58	139	12	81	120	220	16	26	133	215	1,097
2032	79	59	142	13	83	122	223	16	27	135	216	1,115
2033	81	60	144	13	84	124	226	16	27	136	217	1,128
2034	83	61	146	13	85	126	228	17	27	137	218	1,141
2035	85	62	148	13	86	127	230	17	27	137	219	1,151
2036	86	63	149	13	87	129	232	17	28	138	220	1,162
2037	88	64	150	13	88	131	233	17	28	138	222	1,172

Table I-12b: Topline Forecast of Coincident Peak Demand

Prior to Impacts of Energy Saving Programs & Behind-the-Meter Generation

Coincident Summer Peak Demand by Zone - MW

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2018	2,870	2,053	2,954	527	1,361	2,435	2,327	686	1,477	11,583	5,490	33,763
2019	2,888	2,067	2,973	729	1,370	2,450	2,340	688	1,480	11,606	5,508	34,099
2020	2,914	2,084	2,998	732	1,387	2,482	2,356	691	1,485	11,664	5,574	34,367
2021	2,937	2,099	3,020	733	1,397	2,500	2,371	694	1,490	11,713	5,600	34,554
2022	2,958	2,112	3,040	735	1,408	2,516	2,385	698	1,496	11,752	5,627	34,727
2023	2,981	2,130	3,063	738	1,420	2,537	2,402	702	1,503	11,811	5,659	34,946
2024	3,001	2,144	3,081	739	1,430	2,555	2,417	705	1,509	11,858	5,693	35,132

Table I-1: NYCA Baseline Energy and Demand Forecasts

Reflects Impacts of Energy Saving Programs & Behind-the-Meter Generation

2018 Long Term Forecast[1] - 2018 to 2038

Energy - GWh

Year	Low[3]	Baseline[4]	High[3]
2017		156,795	
2018	154,325	156,120	157,915
2019	154,858	156,649	158,440
2020	153,789	155,567	157,345
2021	152,802	154,567	156,332
2022	152,139	153,898	155,657
2023	151,839	153,593	155,347

Summer Peak Demand - MW

Year	Low[3]	Baseline[4, 5]	High[3]
2017		32,914	
2018	30,256	32,904	34,744
2019	30,215	32,857	34,696
2020	30,002	32,629	34,454
2021	29,841	32,451	34,266
2022	29,737	32,339	34,148
2023	29,686	32,284	34,089

Winter Peak Demand - MW

Year	Low[3]	Baseline[4]	High[3]
2017-18		24,265	
2018-19	22,853	24,269	25,884
2019-20	22,726	24,135	25,742
2020-21	22,549	23,948	25,542
2021-22	22,425	23,817	25,401
2022-23	22,364	23,751	25,334
2023-24	22,344	23,730	25,310

The difference in Topline Summer Peak demand for 2018 (33,763 MW) and the Baseline Demand Forecast for 2018 (32,904), equating to 859 MW, includes the projected 440 MW (AC) of BTM PV supply, out of a projected 2018 BTM PV capacity of 1,504 (DC). The precise method by which projected BTM PV AC supply is calculated by NYISO is unclear, however it appears that a ratio, similar to ISO New England, may be utilized: NYISO (440/1504)=29%, ISO New England (632.6/1820.2)= 35%. It is this 440/1504 MW of BTM PV supply that is subjected to the yin-yang effect described in this report and can have a significant impact on actual peak supply/demand.

No attempt is made to ascertain the accuracy or quality of this methodology. The intent of this report is to highlight the various methodologies used by ISO's to produce the forecasted peak demand, with particular attention to the method used to determine the impact of BTM PV supply resources on peak demand, as justification for the need of an industry standard methodology.

Empirical Evidence of Solar Generation Impact

The March 2015 solar eclipse that impacted the European Electric system provides a unique opportunity to experience, first hand, the impact of solar generation on demand. As indicated in [31], around 35,000 MW of solar energy would decrease from Europe's electrical system over the course of just over two hours. TSOs had to balance the unusually speedy loss of solar energy from the grid as shadow overtook the sun, beginning at 9am Brussels time. **The swift loss of around 17GW was then followed by an even speedier (three times the normal maximum, according to Reuters) reintegration of 25GW solar generation as the shadow completed its course.**

The following graphic [31] shows the rapid changes in PV power supply over a three hour period:

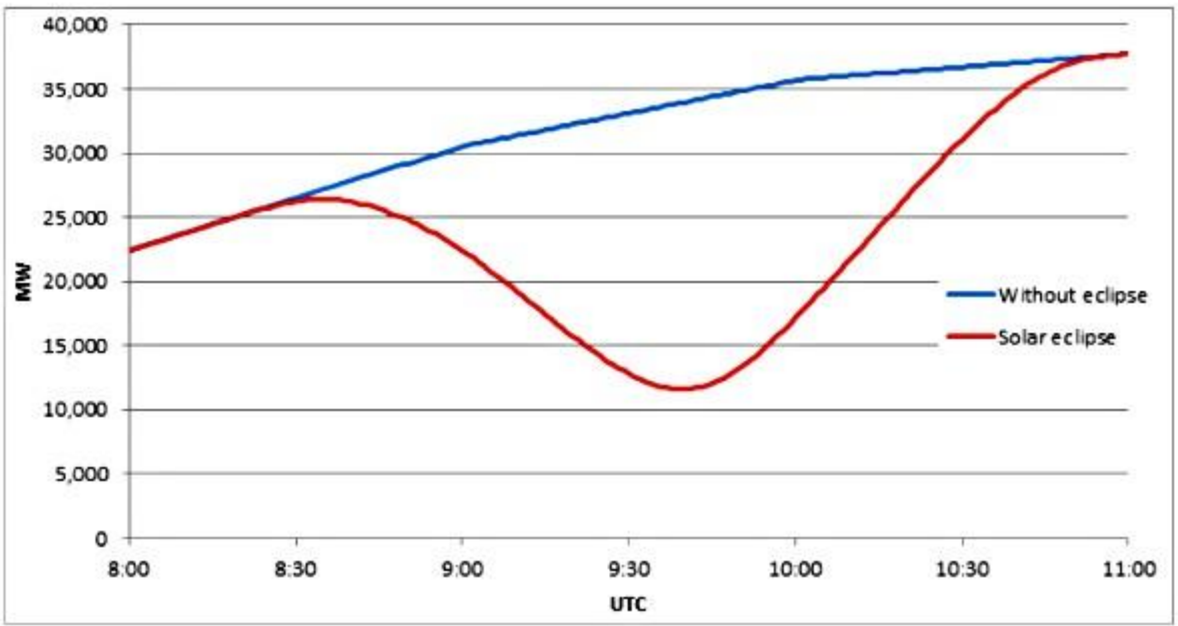


Figure 7. Solar PV Generation during 2015 Eclipse

The empirical data supplied by the 2015 eclipse provides ample evidence of the need for system operators to have flexible, minute by minute, "up and down" ramping capabilities at their disposal, with a response time similar to automatic generation control (AGC), but with finer locational precision. This suggests that ISO's and other Balancing Authorities consider the need for an "Estimated Peak Ramp Rate" (EPRR) to address both the direction (+ or -) and magnitude of the ramping requirement over a specified period of time, perhaps on 5 minute intervals, within areas containing high renewable generation. For example, using the graphic in figure 7 above for the 8:30 through 9:00 time period, the 5-minute EPRR might appear as follows:

Time Interval	EPRR (approximate) (MW)
8:30	+15
8:35	+30
8:40	+55
8:45	+100
8:50	+1,000
8:55	+2,000
30 min total	+3,200

Figure 8. EPRR example using 2015 Eclipse data

A positive value indicates the needed ramping up requirements of power (MW) to increase supply from grid connected generating resources while a negative value represents the ramping down requirement of grid resources, to decrease the amount of power (MW) being supplied, over a defined time period.

Observations and Recommendations

OBSERVATIONS

This report provides insight into the various load forecast methodologies used by ISO New England and the NYISO to factor-in the impact of behind the meter photovoltaic supply resources (BTM PV)

The differences in these two ISO's methodologies serve as an indicator that an industry wide standard for calculating the impact of BTM PV on peak demand is justified, in order to ensure common semantics and business practices across power regions

BTM PV supply resources are unique from other generating resources in that they exhibit a "yin-yang effect" which can have both positive and negative impact on peak demand in a reciprocal relationship; whatever BTM PV supply does not get produced (i.e. due to weather), will likely result in an increase in demand/load approximately equal to the "missing BTM supply"

Insights are offered to differentiate the "old concept" of Peak Demand as representing "maximum consumption of electricity by consumers at a location and specified moment in time", and the newly introduced "Peak Power from Grid Resources" (PPGR), peak demand concept, which represents the amount of peak power needed from grid connected resources.

Observations from the 2015 eclipse depicting rapid changes in supply and demand justify the need for a new risk factor, "Estimated Peak Ramp Rate" (EPRR) addressing the need for both up and down ramping capabilities over a specified time period and geographical area, to consider when forecasting PPGR "peak demand" and the planning of Grid Resources and Ancillary Services, such as operating reserves and regulation

RECOMMENDATIONS

Electric industry stakeholders with responsibility for ensuring reliability of the grid should consider initiating discussions on the need for an industry wide standard methodology to factor-in the yin-yang effect (impact) of Behind the Meter Photovoltaics generators (BTM PV) on load forecasts/peak demand, expressed as Peak Power from Grid Resources (PPGR), and future capacity requirements, along with the need for a locational "Estimated Peak Ramp Rate" (EPRR) to address the rapid minute-to-minute changes in supply/demand, like those observed in Europe during the March 2015 eclipse.

ABOUT THE AUTHOR

Richard "Dick" Brooks is a Professional Software Architect with over 30 years of software engineering accomplishments, primarily serving the Energy industry. He was co-founder and Chief Technical Officer of Group 8760 where he led development of the Company's market leading B2B software product, Inside Agent, a NAESB EDM software package, that reliably processes $65 Billion in transactions annually. He gained international acclaim as a co-author of the UN/CEFACT - OASIS ebXML Message Service Specification and was appointed to serve as the liaison assigned to the World Wide Web consortium where he coordinated the convergence of ebxml and SOAP. Serving under Dave Darnell of Systrends he worked as an Advisor to Eirgrid, the ISO for Ireland, where he developed a framework for the Company's Security Architecture. In 2004 he joined ISO New England as the Company's Enterprise Architect, serving under Eugene Litvinov, where he developed, and successfully implemented the Company's enterprise wide Service Oriented Architecture, co-authored the Company's Smart Grid white paper, co-authored an award winning DOE Smart Grid funding proposal to install PMU devices, and led industry wide standards development at NAESB, which earned him an ANSI Meritorious Service Award, and the ISO/RTO Council (Enterprise Architecture Standards V1.0). As a Technical Lead and Principal Information Architect he led development of ISO New England's Business Intelligence and Data Analytics platform over eight years and created the most widely utilized analysis used throughout ISO New England, the Market Monitoring Department FPA Viewer. After an early retirement from ISO New England in 2018 he started Reliable Energy Analytics. He has been a member of the IEEE and ACM for over 30 years. He can be reached at dick@reliableenergyanalytics.com

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