VIA ELECTRONIC FILING

April 18, 2016

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

Re: CASE 15-E-0751 In the Matter of the Value of Distributed Energy Resources – Notice Soliciting Comments and Proposals on an interim Successor to Net Energy Metering

Dear Secretary Burgess:

The New York Battery and Energy Storage Technology Consortium ("NY-BEST") is pleased to submit these comments for your consideration in the above referenced case in relation to Notice Soliciting Comments and Proposals on an interim Successor to Net Energy Metering and the Value of Distributed Energy Resources (DER).

NY-BEST and our more than 150 member organizations from across New York State and beyond appreciate the opportunity to provide these comments and we stand ready to assist the Department of Public Service (DPS) staff and the Public Service Commission (PSC) in establishing a methodology, and interim methods, for valuing DER and designing rates for DER providers.

If you have any questions or require additional information regarding these comments, please contact me at (518) 694-8474.

Respectfully,

William P. Acker
Executive Director

NY-BEST COMMENTS

CASE 15-E-0751 In the Matter of the Value of Distributed Energy Resources

INTRODUCTION

The New York Battery and Energy Storage Technology Consortium ("NY-BEST") is a not-for-profit industry trade association that serves as the voice of the industry for more than 150 member organizations on matters related to advanced batteries and energy storage technologies. Our membership covers the full span of activities related to research, development, production and deployment of energy storage devices, and currently includes technology developers ranging in size from small start-up companies to global leaders, leading research institutions and universities, national labs and numerous companies involved in the electricity and transportation sectors.

Our mission is to catalyze and grow the energy storage industry and establish New York State as a global leader in energy storage. We do this by:

(1) Acting as an authoritative resource on energy storage, proactively communicating energy storage related news and information, and facilitating connections amongst stakeholders;
(2) Advancing and accelerating the commercialization process for energy storage technologies, from research and development, to products and widespread deployment;
(3) Educating policymakers and stakeholders about energy storage and advocating on behalf of the energy storage industry; and
(4) Promoting New York's world-class intellectual and manufacturing capabilities and providing access to markets to grow the energy storage industry in New York.

NY-BEST has been actively engaged in the State's Reforming the Energy Vision (REV) initiative and its related proceedings since its inception and supports NYS Public Service Commission's (PSC) efforts to transform New York's electric industry with the objective of creating market-based, sustainable products and services that drive an increasingly efficient, clean, reliable, and customer-oriented industry. We also support the goals of the State's Energy Plan and the Clean Energy Standard to generate 50 percent of the state's electricity from renewable sources by 2030 and reduce greenhouse gas emissions by 40 percent by 2030 and 80 percent by 2050. Energy storage is a key enabling technology for the State to achieve these policy goals. Accordingly, as the Department begins its efforts to develop methodologies to value DERs, including energy storage, we encourage the Commission to adopt mechanisms that fully value and account for the benefits and services provided by storage.

Overview of Comments

The Notice for Comments outlines two specific tasks:

1.) Identify an interim approach to valuing DER including a transition plan for moving from net metering to DER valuation that can be adopted prior to December 31, 2016; and

2.)Establish a methodology and process for determining the full value of DER for the larger purposes of developing DER compensation mechanisms built upon LMP+D approach.

Our comments are organized to respond to the above outlined tasks. We provide general comments on transitioning to a LMP+D methodology; propose potential interim methods for valuing DER benefits and costs and designing appropriate rates and valuation mechanisms; and outline key principles for establishing a full LMP+D market mechanism. We have included three specific proposals for the staff and Commission's consideration that could create mechanisms for valuing DER benefits at the distribution level in the near term.

General Comments – The Value of D and LMP+D

NY-BEST greatly appreciates and commends the DPS staff and the Commission for commencing this proceeding on the value of DER. We have previously articulated that we view LMP+D as being at the heart of accomplishing the goals of REV. NY-BEST envisions over the longer term the electric grid to be a bidirectional, transactive, and situationally-aware system that supports the following principles:

- Transactive nodes across the grid, with bidirectional interconnections and "prosumers" (producer-consumers) buying and selling energy products and services;

- The elimination of barriers to entry, allowing new technologies to participate in the electric grid and ensuring that the batteries and energy storage are not excluded;

- The valuation of products and services based on transparent and standardized methodologies, procedures and processes through the unbundling of the costs and benefits of energy resources in providing products and services to the grid, ensuring that each DER's value streams are appropriately and fairly captured; and

- The elimination of competitive barriers so that each resource can participate on a level playing field.

Moving to a full LMP+D market mechanism that encompasses all of the benefits articulated in the Benefit Cost Analysis Framework is integral to achieving this vision over the longer term.

In the meantime, however, NY-BEST and our members remain concerned that the prolonged REV process and resulting market uncertainty is hindering private investment in the state. Specifically, uncertainty in future revenue and market risk are causing private capital to wait to enter the market.

For purposes of creating market certainty and ensuring consumer confidence, NY-BEST agrees with several other stakeholder groups commenting that the State's existing net energy metering program should be grandfathered for existing systems, allowing small generators of electricity to sell excess generation into the grid, subject to an overall cap. Going forward a new system should be designed that incorporates locational marginal energy prices and an added value for distributed energy resources, as articulated in the Benefit Cost Analysis Framework.

We are concerned, however, that the Commission's initial focus in developing interim programs to replace net energy metering is primarily centered on establishing methods that create locational value for energy services from DER and may not adequately recognize and create locational value for other important DER services and benefits, such as capacity and grid services (frequency response and regulation, spinning reserves, voltage/VARs support, system control and dispatch, etc.). These services are essential to the achieving the State's goals of reducing peak demand and supporting the increased penetration of renewable energy. Importantly, energy storage provides all of these benefits and energy storage providers are currently unable to fully monetize these benefits.

NY-BEST strongly supports an iterative approach to a developing a full market LMP+D mechanism. We believe there is an immediate need to create new methods that will give confidence, stability, and visibility to future revenue streams to DER providers for a host of DER services and benefits, including energy, capacity and grid services. NY-BEST encourages the Commission to adopt interim programs that will begin to animate markets and spur private investment in New York markets.

Interim Approaches

In the interest of moving toward a market mechanism that embraces a full LMP+D methodology for DER, NY-BEST is proposing three potential options for the consideration by Department staff and the Commission. NY-BEST believes that interim approaches to establishing a LMP+D market should be designed to provide an upfront valuation for "D" that will reduce uncertainty for project developers and limit market volatility. Without some reasonable level of revenue certainty, DER projects will likely not be built.

NY-BEST also believes that a single interim program will likely not be sufficient for all technologies and a number of interim programs may be necessary. The proposals outlined below include optional or opt-in voluntary programs that would allow the State to begin to make steps toward valuing numerous benefits of DER.

<u>Asset Utilization Tariff Proposal</u>

As an interim measure, NY-BEST encourages the Commission to consider adopting cost effective measures that value storage and other DER technologies. This can be done by creating an "Asset Utilization Tariff" that is technology neutral and is based on the cost savings to each utility from reduced ICAP, T&D deferral, distribution system peak load management and energy savings. For example, the Asset Utilization Tariff could be applied to energy storage on a stand-alone basis or to energy storage paired with distributed solar and used to reduce peak load and increase utilization. The form of this tariff could be similar to the current ConEd Demand Management Incentives program, with the important difference that:

1) the compensation ($/kW) would be based on the avoided cost and not limited to 50% of the asset capital cost; and
2) Both behind-the-meter and in-front of the meter applications that provide the benefits would qualify for the tariff.

(This proposal was previously raised by NY-BEST in the Demand Response Tariff Proceeding, PSC Case 14-E-0423, and recognized by the Commission in the PSC Order dated, June 18, 2015.)

The proposed Asset Utilization Tariff is designed to improve grid utilization rates. Grid-connected energy storage projects and distributed solar operating in New York today can only monetize the benefits valued by the NYISO wholesale energy market or the customer, such as capacity/demand charges, energy and ancillary services. However, there are a number of other benefits that this combination delivers that are not effectively captured or monetized by the owner of the asset. The proposed Asset Utilization Tariff will allow these assets to monetize new value streams in partnership with the utility.

NY-BEST believes that an Asset Utilization tariff would create benefits for the grid, the utility, the customer and third parties. For example, utilities serving as the DSP are tasked with insuring system reliability including the need to upgrade local distribution network to meet the summer peak load. PSC has estimated that the costs savings provided by improving the utilization rates by 1% (from 55% to 56%) is approximately $220-$330 million per year. The savings vary by zone, but PSC estimates that the Transmission and Distribution deferral benefits in New York City alone (Zone J) are $305/kW per year. The proposed Asset Utilization Tariff would be based on the cost savings to each utility from a reduction in ICAP, T&D deferral, and Energy savings achieved. The proposed Tariff would be for a fifteen or twenty year term and would be subject to an annual cap. The proposed Tariff would be technology agnostic (e.g. solar, battery, demand response or energy efficiency), would encourage both in-front-of and behind-the-meter resources, and would allow developers to bundle products together to best meet the peak load and asset utilization requirements of the tariff. The proposed tariff will provide a win-win-win arrangement between the utility, customer, and third parties because all parties will have an incentive to perform and it is expected to lower costs to the utility customers. The utility would earn a return on this tariff as compensation for the distribution-level benefits accrued. Third parties would be able to own and operate the asset under the tariff regime and earn additional revenue in the wholesale market and/or through agreements with individual customers.

The proposed tariff would also enhance electric system reliability without producing emissions, reduce overall system emissions and increase system utilization rates.

Load Reduction Rate

NY-BEST encourages the Commission to consider adopting a Load Reduction Rate mechanism[1] geared toward reducing peak demand and engaging buildings as customers. This proposal recognizes that the cost to deliver power has both locational and time-based value for utilities and delivering power at peak times creates higher system losses. The proposed Load Reduction

[1] Load Reduction Rate Proposal was developed by Demand Energy Networks and is presented with permission granted by Demand Energy Networks. See Appendix A PPT Proposal for additional details.

Rate mechanism is envisioned as a voluntary program based on hourly pricing for power (demand) under a new rate structure that encourages load reduction during the four peak hours of the local distribution network and creates “shoulder” rates that reduce the cost of power at times when it is less expensive to deliver. Locational Based Rates would be established by network or at the circuit level and align to when peaks occur on each network or circuit, thereby aligning with system need.

The design of the Load Reduction Rate is based upon current Standby Rate design. Under the current Standby Rate, As-Used Daily Demand Charges are measured and billed daily. The As-Used Daily Demand Charge value is only measured between 8 AM until 10 PM. Nights (10 PM to 8 AM) and Weekends are free, and no demand charges are billed. The Contract Demand Delivery Charge ($7/kW-Fixed) covers the off-hours where the As-Used Daily Demand Charge is not measured. The buildings historic peak is used to bill the monthly component of the Contract Demand Delivery Charge (Historic Peak Demand kW x $ 7/kW= Monthly Fixed Charge).

To develop the load reduction rate, the 14 hour measurement period of the current Standby rate was dissected into 14 hourly price periods and will capture the peak demand for each hour, so that every hour, there will be a charge for demand ($/ kW) times the Peak Hourly Demand value (kW). The Load Reduction Rate increases the current As-Used Daily Demand Charge from $1.44/ kW to $1.60/kW and then allocates four hours to have a higher charge for the peak periods along with a shoulder hour on either side of the peak hours and then off-peak pricing during the other eight hours remaining. The four peak hours would coincide with the networks four peak load hours which can be different across a utility’s service territory. As an example, we present the following Table with different Demand Values comparing the hourly rate (based upon a $1.60 daily total) with the hourly rates as shown.

Summer			
Time of Day	Base Hourly Rate= $/kW	Demand	Hourly Charge
1:00	$ -	261	$ -
2:00	$ -	250	$ -
3:00	$ -	248	$ -
4:00	$ -	244	$ -
5:00	$ -	251	$ -
6:00	$ -	264	$ -
7:00	$ -	288	$ -
8:00	$ 0.050	287	$ 14.35
9:00	$ 0.050	272	$ 13.60
10:00	$ 0.050	304	$ 15.20
11:00	$ 0.050	269	$ 13.45
12:00	$ 0.050	281	$ 14.05
13:00	$ 0.100	272	$ 27.20
14:00	$ 0.250	284	$ 71.00
15:00	$ 0.250	291	$ 72.75
16:00	$ 0.250	277	$ 69.25
17:00	$ 0.250	278	$ 69.50
18:00	$ 0.100	289	$ 28.90
19:00	$ 0.050	301	$ 15.05
20:00	$ 0.050	300	$ 15.00
21:00	$ 0.050	305	$ 15.25
22:00	$ -	310	$ -
23:00	$ -	276	$ -
0:00	$ -	268	$ -
Total	$ 1.600		$ 454.55
Under Current Standy			
Peak	$ 1.440	305	$ 439.20

Based upon the current $1.44/kW for Daily as used, the Load reduction rate is higher priced but the four peak hours are priced @ 25¢/kW with a 10¢/kW shoulder hour and 5¢/kW off peak period. There is no charge for demand from 10 PM until 8 AM just as the Standby rate operates today.

There is a $1200/kW Load Reduction enablement payment that secures the right for the utility to step in and set the load reduction schedule on days where there are Commercial System Relief Program (CSRP) events. This enablement payment helps pull the customer payback period into a range that is required to encourage involvement in the program.

A Load Reduction Rate would essentially create an "LMP+D-like" rate for Demand Response and establish rates as an energy charge tied to time, per kW by hour. Under this type of mechanism, facilities with controllable demand response would be eligible to voluntarily participate. This proposal also envisions a Market Based Earnings mechanism for utilities in the form of performance based rate making. The proposed program would be voluntary and utilities would have the ability to override on critical days.

This methodology could be used for net exports as well where the same formula applies and is used to generate a form of a capacity payment.

By reducing load at peak times and shifting the storage of energy needed at peak to off-peak periods, this type of rate would help improve the overall system utilization factor of the grid.

Reauthorize NYSERDA/ConEdison DMP Program

NY-BEST encourages the Commission to consider reauthorizing the NYSERDA/Con Ed Demand Management Program (DMP) or adopt a new similar program to incentivize investments in demand management. The existing program funding is fully subscribed and there is currently a pipeline of projects that are unable to move forward due to insufficient program funding. NY-BEST and several of our members have worked diligently with New York City agencies and others to establish a siting process for battery projects and with additional funding through this or a similar program, we are confident that these efforts will yield benefits with new energy storage projects being approved in New York City.

The existing DMP program offers enhanced incentives for technologies that help improve operational performance of buildings and reduce electric demand. Building owners and building managers, who are Con Edison electric customers and third party developers acting on behalf of the building owners and managers, are eligible for the incentives based on their demand reduction for energy efficiency and demand management projects that are completed prior to June 1, 2016.

Incentives are available to eligible customers for energy improvements that contribute to the reduction of the system-coincident peak demand during the summer months. Types of projects that are eligible for the DMP incentives include:

Project Type	DMP Incentives
Thermal Storage	$2,600/kW
Battery Storage	$2,100/kW
Chiller/HVAC/BMS/Controls	$0.16/kWh + $1,250/kW
Lighting/LED	$0.16/kWh + $800/kW
DR Enablement	$800/kW
Fuel Switching: Non-Electric A/C*	$500 - $1,000/kW

***Incentives will be offered for installing steam or natural gas A/C rather than electric A/C.**

Projects that achieve a peak reduction of 500 kW or more can also earn additional bonus incentives.

Bonus Incentives	
Projects over 500kW	+10% of kW incentive
Projects over 1MW	+15% of kW incentive

Incentives are capped at 50% of installed project cost and bonus incentives are available for large projects over 500 kW.

NY-BEST encourages reauthorization of this program with modifications to include in-front of the meter storage projects and to reflect current market conditions. Specifically, we would recommend eliminating the incentive cap of 50 percent of installed project costs in consideration for a lower $/kW incentive. For example, NY-BEST would recommend consideration of a $1,200-$1,800 per kW incentive in ConEdison territory.

Creating a LMP+D Market Methodology in the Long Term

NY-BEST believes that LMP+D rate design is critical to the success of REV. Ideally, NY-BEST believes that LMP+D rates established to achieve the REV goals should:

- Ultimately be standardized across utilities (DSPs) and technologies - the rate construct and technology options should be uniform with locational pricing using a uniform method of calculation that may result in different tariff pricing by utility and/or within certain utility locations;
- "Unbundle" costs to the end customer to allow multiple benefit streams to storage and other technologies;
- Locational pricing should apply to other products beyond just energy and encompass capacity and grid services (See Appendix B – DER Products and Services Matrix).
- Provide for locational and temporal granularity (Because benefits can differ with location down to individual distribution circuits, the degree of locational granularity is important); and
- Allow flexibility to respond to market and load conditions.

NY-BEST recommends implementation of three dimensions of granularity:

- **Temporal—**Time-differentiating prices that vary in response to marginal price.

- **Locational—**Reflecting congestion or capacity constraints in pricing; for example, locational marginal pricing or distribution locational marginal pricing.

- **Attribute—**Unbundling rates to reflect the individual attributes embedded in electricity service; for example, energy, capacity, ancillary services, environmental impacts, or others.

NY-BEST believes the value of D will vary based upon a number of factors and that the values stack will be different for different technologies. We also believe that rate design and compensation mechanisms implemented under REV should be granular at the circuit where the value of the DER will be realized, not based on system-level average values.

Importantly, NY-BEST wishes to stress that when valuing the environmental benefits of storage, whether storage is paired with renewable energy or not paired with renewable energy, storage reduces the need for ramping fossil generators and dirtier peaker plants and thus reduces emissions. As a result, simply assuming that the emissions measurement for storage not paired with renewable energy should be based on the average generation mix in the state incorrectly understates the positive impact of reduced emissions from storage.

CONCLUSION

NY-BEST greatly appreciates the efforts of DPS staff and the Commission to develop methodologies and interim mechanisms to value DERs. As stated above, we support the goals of the REV initiative and we believe energy storage is a key enabling technology to achieve those goals. Our primary concern is that appropriate interim measures, which place a value on capacity and grid services, as well as energy, be put in place in the near term to ensure that the DER markets in New York are not stalled while work continues on a full LMP+D market model.

NY-BEST also requests that the Commission allow for reply comments to be submitted in this matter as we would like the opportunity to review and comments on proposals from other parties.

We appreciate the opportunity to provide these comments and we stand ready to assist the Department, Commission, utilities and all stakeholders as these and other REV-related proceedings continue.

Respectfully submitted,

William P. Acker
Executive Director
NY-BEST
1450 Western Ave, Suite 101
Albany, NY 12203

Appendix A

Demand Energy Networks

Intelligent Distributed Energy Storage

Con Ed RFI for Energy Storage REV Demo

Innovative Energy Storage Business Models

Issued: February 2, 2016

Submission Deadline: March 25, 2016

Basic Theory

- The cost to deliver Power has both a locational and time based value for Con Ed.
- Delivering Power at peak time periods creates higher system losses
- By reducing load at peak and shifting the storage of the energy needed at peak to off-peak periods helps improve the overall system utilization factor of the Grid.
- Develop hourly pricing for Power (Demand) under a new rate structure that encourages load reduction during the four peak hours of the local network and to have shoulder rates that reduce the cost of Power at times when it is less expensive to deliver.
- Develop Market Based Earnings that Con Ed can earn from as a form of performance based rate making.

Determining Value of LBMP+D

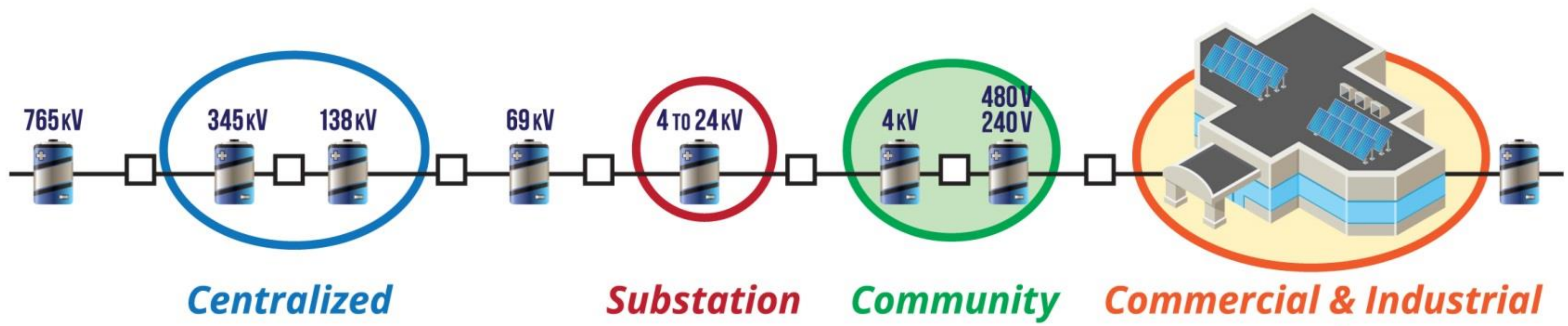
UTILITIES

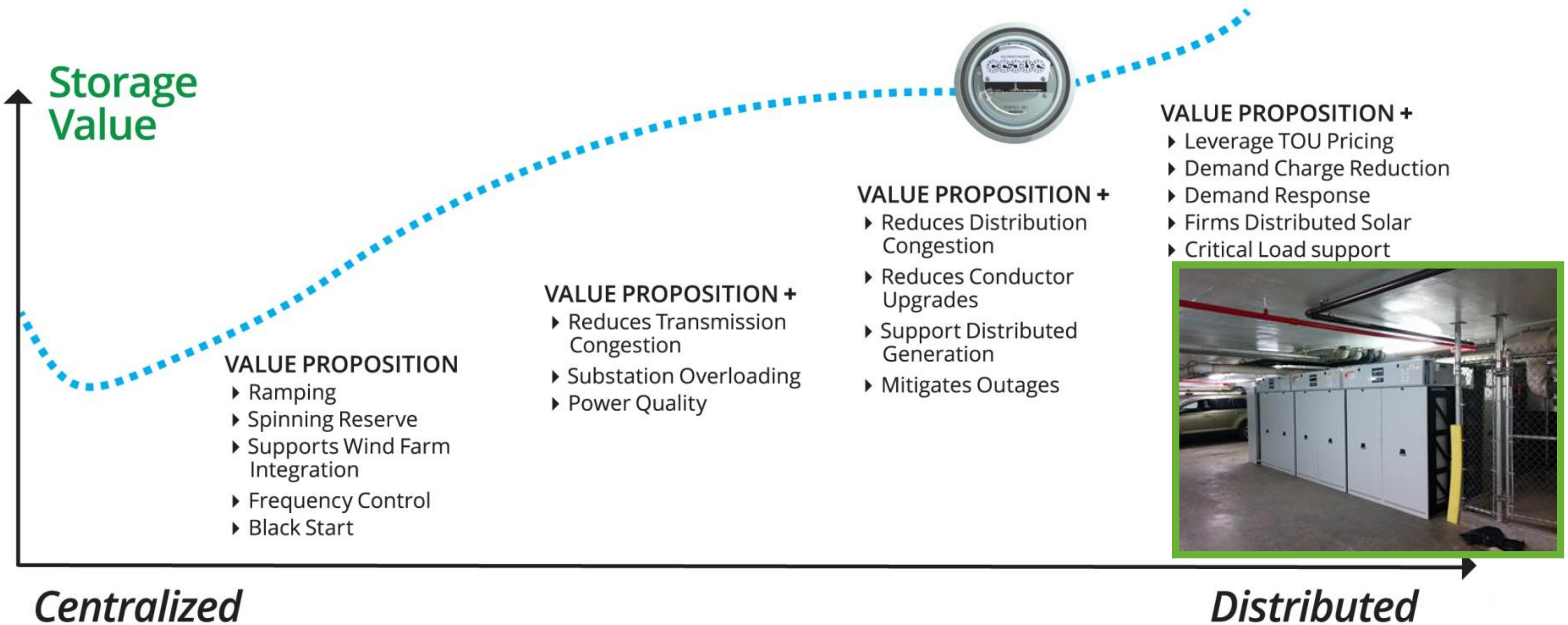
- Conversion of variable generation to base load generation
- Better utilization of Transmission & Distribution resources
- Integration of Renewable Generation
- Better solution to Demand Response
- System balancing-Load, Frequency-Voltage
- Lessen the impact of EV Charging integration

CUSTOMER SIDE

- Take Advantage of Market Price Incentives- TOU & Demand
- Demand Response w/o load reduction
- Overall Load management
- Renewable Integrations- Net Zero
- Disaster Response Services
- Minimize EV Demand Charges

Locational Value of Storage





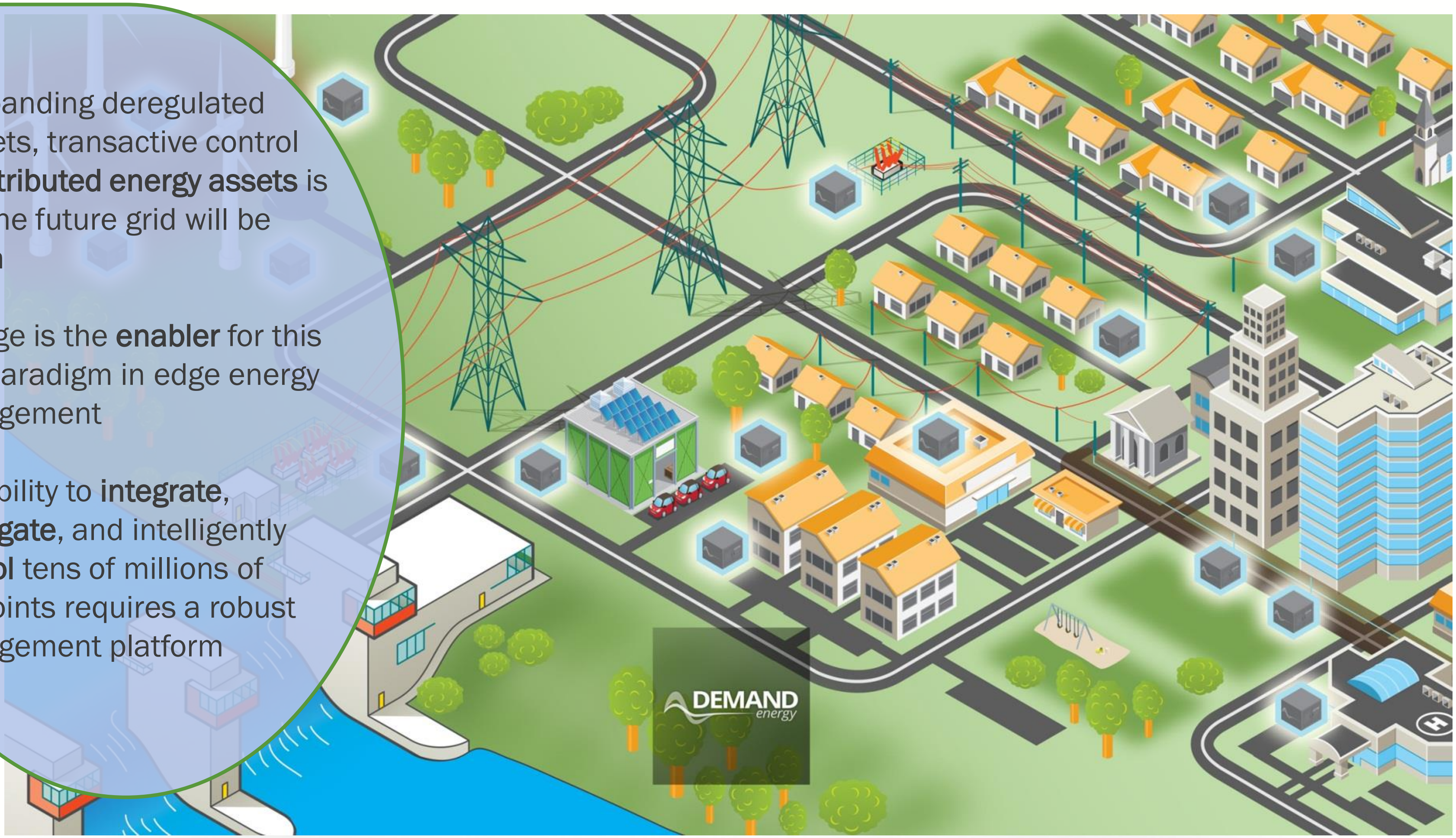
Distributed Intelligent Power Network

DEMAND energy
Take charge.

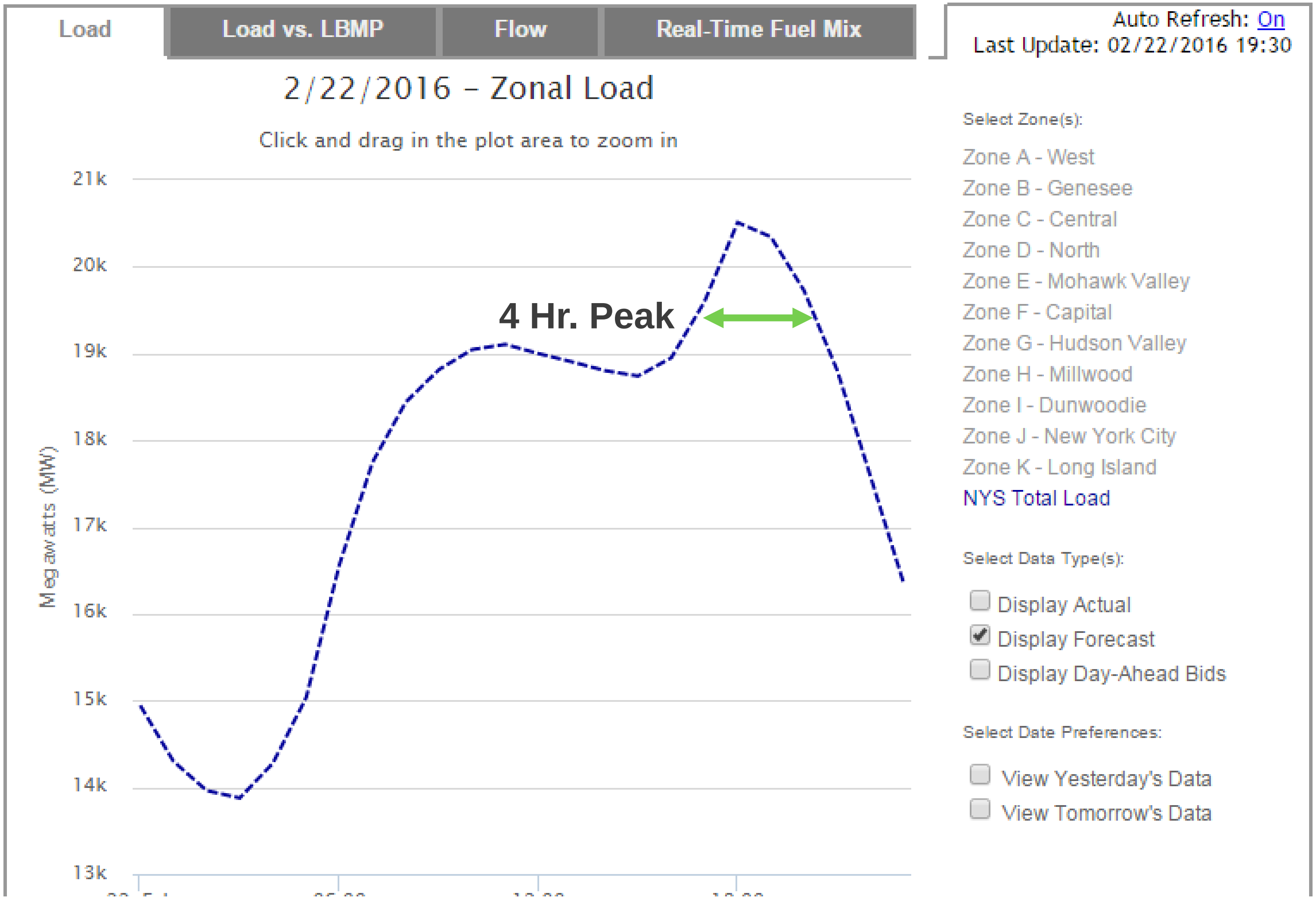
- In expanding deregulated markets, transactive control of **distributed energy assets** is how the future grid will be driven

- Storage is the **enabler** for this new paradigm in edge energy management

- The ability to **integrate**, **aggregate**, and intelligently **control** tens of millions of endpoints requires a robust management platform



New York Load Data

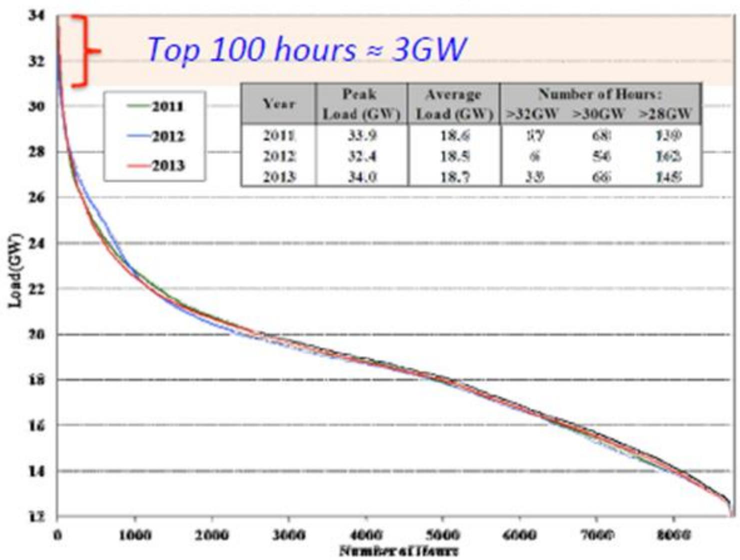


NYC Load Duration Curve

Trapped Value in Peak Demand

"If, for example, the 100 hours of greatest peak demand were flattened, long term avoided capacity and energy savings would range between $1.2 billion and $1.7 billion per year."
-NY PSC Order Adopting Regulatory Policy Framework and Implementation Plan [REV], 2/26/15

NY ISO Load Duration Curves, 2011 -2013



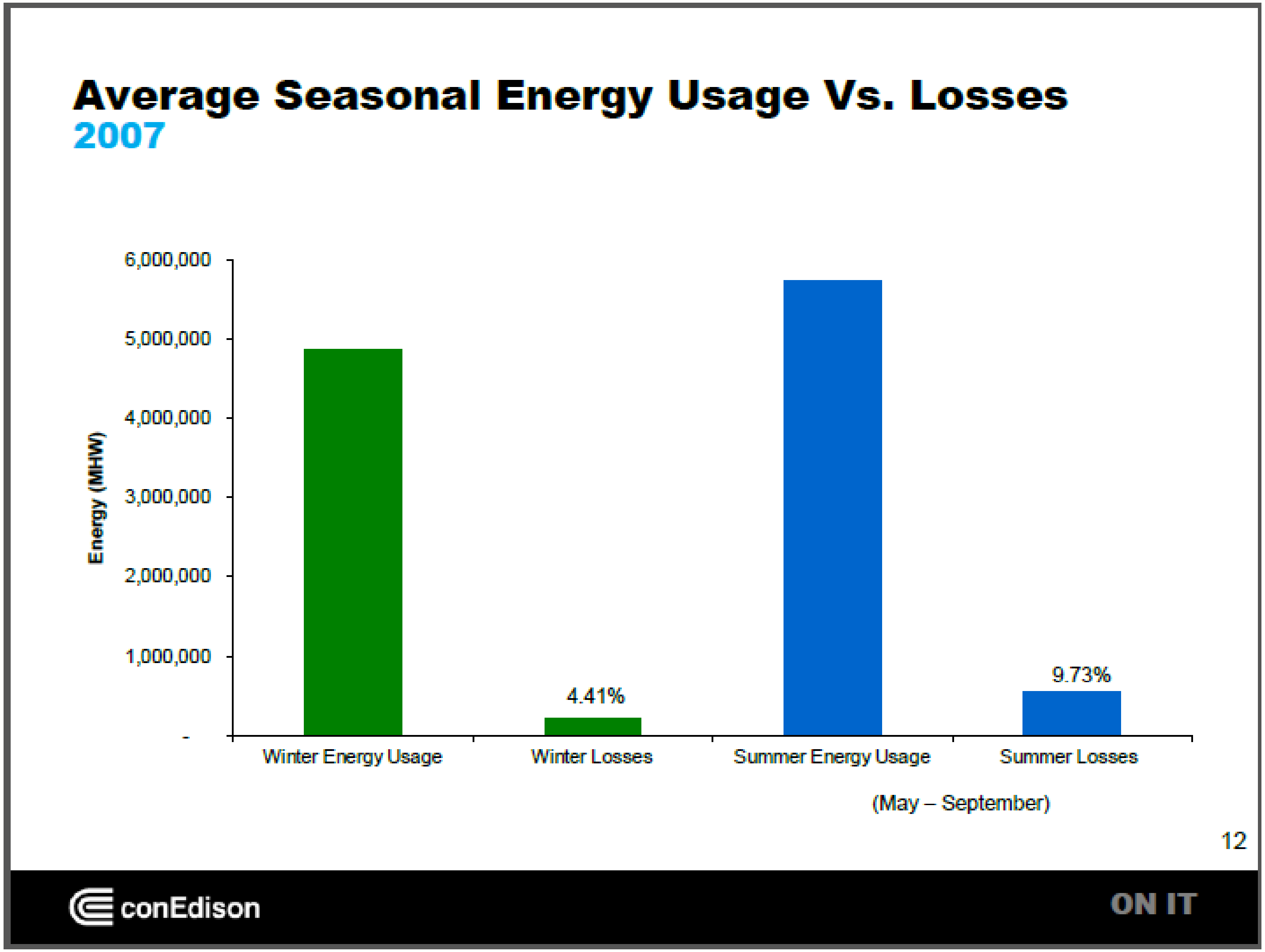
Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2011	33.9	18.6	17	68	130
2012	32.4	18.5	6	56	162
2013	34.0	18.7	33	66	145

Source: 2013 NYISO SOM Report, Potomac Economics.

Cost of NYS Peak Demand	
Top 100 hours = 3 GW statewide *(1.4 GW NYC alone)*	
Low Average @ $1.2 billion	High Average @$1.7 billion
$400 / kW	**$567 / kW**
$0.40 / kWh	**$0.57 / kWh**

Source: Consolidated Edison

Con Ed Line Losses



Time Variable Distribution "Cost"

Line Loss is typically thought of as equal throughout a delivery day. In Reality they are a function of the line amperage to a squared power

Line Loss is estimates are often averaged

- Energy Generated-Energy Delivered

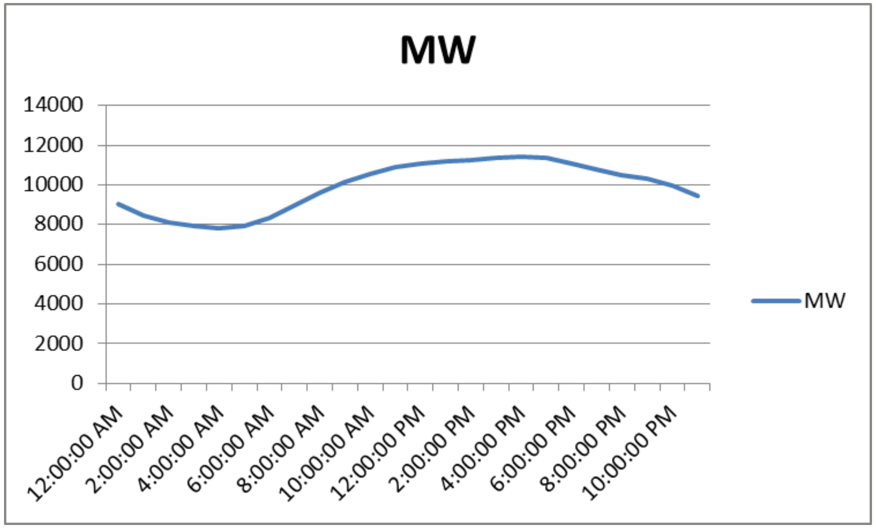
  Energy Generated

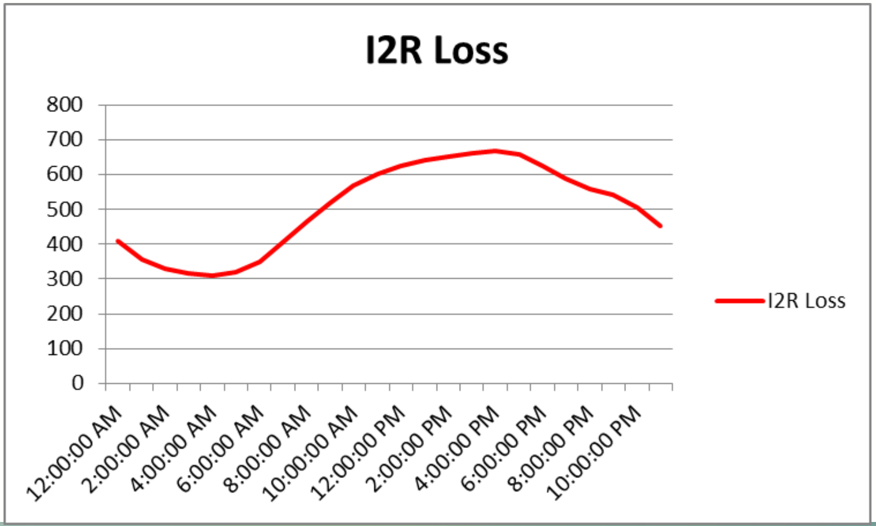
  Measured over a set time period (24 Hrs)

- Line Loss is not Linear to Load. It is a Squared Function

Peak Load / Trough Load: $\frac{11441\ MW}{7827\ MW} = 1.46$

Peak Loss: $\frac{670\ MW}{310\ MW} = 2.15$





Con Ed Network Peak Substations

- Load Reduction during regional peak delivers value to Con ED
- Load Reduction Incented by Time Based Hourly Demand Charges
- 4 Hours of Peak Load Reduction encouraged by higher hourly pricing

Con Edison Demand Response Programs
Commercial System Relief Program (CSRP)
Event Call Windows for 2016

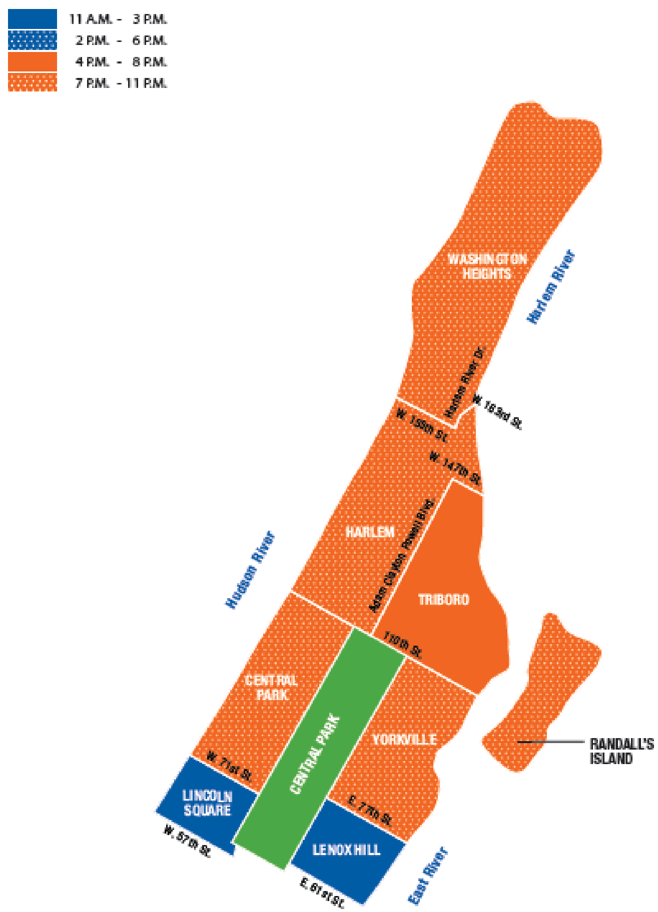
11:00 AM - 3:00 PM	2:00 PM - 6:00 PM	4:00 PM - 8:00 PM	7:00 PM - 11:00 PM
BATTERY PARK CITY	BAY RIDGE	COOPER SQUARE	BRIGHTON BEACH
BEEKMAN	CANAL	FOX HILLS	CENTRAL BRONX
BORDEN	CHELSEA	FRESH KILLS	CENTRAL PARK
BOROUGH HALL	EMPIRE	OCEAN PARKWAY	CROWN HEIGHTS
BOWLING GREEN	FASHION	RICHMOND HILL	FLATBUSH
CITY HALL	HERALD SQUARE	SUNNYSIDE	FLUSHING
COLUMBUS CIRCLE	HUDSON	TRIBORO	FORDHAM
CORTLANDT	LONG ISLAND CITY	WAINWRIGHT	HARLEM
FREEDOM	PARK SLOPE	WEST BRONX	JACKSON HEIGHTS
FULTON	ROCKEFELLER CENTER	WILLIAMSBURG	JAMAICA
GRAND CENTRAL	ROOSEVELT	WILLOWBROOK	MASPETH
GREELEY SQUARE		WOODROW	NORTHEAST BRONX
GREENWICH			PROSPECT PARK
HUNTER			RANDALL'S ISLAND
KIPS BAY			REGO PARK
LENOX HILL			RIDGEWOOD
LINCOLN SQUARE			RIVERDALE
MADISON SQUARE			SHEEPSHEAD BAY
PARK PLACE			SOUTHEAST BRONX
PENNSYLVANIA			WASHINGTON HEIGHTS
PLAZA			YORKVILLE
SHERIDAN SQUARE			
SUTTON			
TIMES SQUARE			
TURTLE BAY			

Con Ed Manhattan Peak Times

DEMAND energy
Take charge.

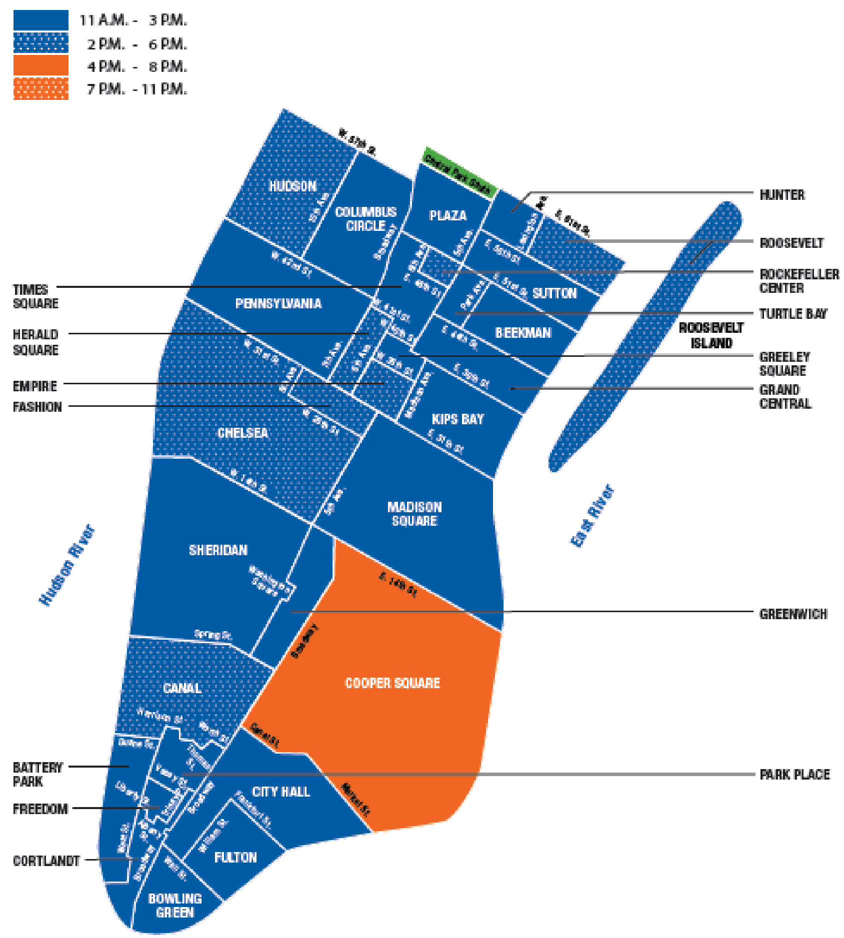
Manhattan (North) Map

conEdison



Manhattan (South) Map

conEdison



Bulk Load Reduction 2-19-2015

NYISO 4 Hour Load Reduction

Rate Evolution

DEMAND energy
Take charge.

Monthly

Electricity you used during this 29 day billing period from Apr 03, 2012 to May 02, 2012
Rate: EL9 General Large **Meter#** 8023664

We measure your electricity by how many kilowatt hours (kWh) you use. One kWh will light a 100 watt bulb for 10 hours. The meter multiplier is the factor by which the meter reading difference is multiplied to determine your usage. Demand or kW is the highest amount of electric usage in any half hour during the billing period.

May 02, 12 actual reading	8227	18.46
Apr 03, 12 actual reading	-7987	-17.97
Reading difference	240	.49
Meter multiplier	X800	X800
Your electricity use	192,000 kWh	392.00 kW

▸Your supply charges

These charges are for the delivery portion of your electricity bill. You will receive a separate bill for your electricity supply. If you have a question about your supply bill, please call CONEDISON SOLUTIONS at (800) 789-1565.

▸Your delivery charges

Energy delivery 192,000 kWh $9,080.73
Charge for maintaining the system through which Con Edison delivers electricity to you.

Demand delivery 392.0 kW $6,682.36
Charge for maintaining the system through which Con Edison delivers electricity to you.

Total delivery charges $18,817.50

▸▸ Total electricity charges $18,817.50

Daily

Name: BARCLAY ST DEVELOP MENT LLC Account Number: 49-4013-8030-0000-5 Billing period ending: Aug 30, 2013

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As Used Daily Demand

DATE	WD=Weekday or WE=Weekend	PERIOD 1: MON - FRI 8 AM - 6 PM			PERIOD 2: MON - FRI 8 AM - 10 PM		
		DAILY DEMAND kW	STANDBY	MAC	DAILY DEMAND kW	STANDBY	MAC
08/02/2013	WD	368.6	$159.60	$17.73	372.9	$367.79	$40.83
08/03/2013	WE	-	$0.00	$0.00	-	$0.00	$0.00
08/04/2013	WE	-	$0.00	$0.00	-	$0.00	$0.00
08/05/2013	WD	346.5	$150.03	$16.67	363.3	$358.32	$39.78
08/06/2013	WD	348	$150.68	$16.74	355.6	$350.73	$38.94
08/07/2013	WD	372	$161.08	$17.89	381.6	$376.37	$41.79
08/08/2013	WD	391.6	$169.56	$18.84	421.9	$416.12	$46.20
08/09/2013	WD	432					
08/10/2013	WE	-					
08/11/2013	WE	-					
08/12/2013	WD	367.2					
08/13/2013	WD	381.6					
08/14/2013	WD	335.5					
08/15/2013	WD	331.2					
08/16/2013	WD	356.6					
08/17/2013	WE	-					
08/18/2013	WE	-					
08/19/2013	WD	366.7					
08/20/2013	WD	382.5					
08/21/2013	WD	394.5					
08/22/2013	WD	402.2					
08/23/2013	WD	374.4					
08/24/2013	WE	-					
08/25/2013	WE	-					
08/26/2013	WD	374.8					
08/27/2013	WD	409.9					
08/28/2013	WD	408.5					
08/29/2013	WD	404.6					
08/30/2013	WD	410.4					

Hourly

Day Ahead Market Zonal LBMP

--- LBMP $ --- Marginal Cost of Losses --- Marginal Cost of Congestion

Zonal Prices **Date: 04/28/2015**

Name PTID	00:00 EDT	01:00 EDT	02:00 EDT	03:00 EDT	04:00 EDT	05:00 EDT	06:00 EDT	07:00 EDT	08:00 EDT	09:00 EDT	10:00 EDT	11:00 EDT	12:00 EDT	13:00 EDT	14:00 EDT	15:00 EDT	16:00 EDT	17:00 EDT	18:00 EDT	19:00 EDT	20:00 EDT	21:00 EDT	22:00 EDT	23:00 EDT
CAPITL	19.98	18.18	17.39	16.58	17.65	20.59	32.91	35.00	28.59	29.22	31.15	32.13	31.22	26.50	26.76	25.83	27.04	26.62	25.55	28.08	36.75	27.37	23.87	21.55
61757	0.74	0.73	0.74	0.74	0.77	0.84	1.02	1.18	1.59	1.55	1.66	1.60	1.52	1.38	1.21	1.21	1.29	1.35	1.45	1.57	2.18	1.50	1.31	0.83
	-3.89	-2.33	-1.91	-0.96	-1.54	-2.66	-11.12	-10.31	-1.36	-2.75	-2.80	-5.52	-5.64	-2.84	-6.11	-5.03	-4.51	-3.14	-0.77	-1.59	0.00	0.00	0.00	-3.71
CENTRL	15.76	15.40	15.00	15.07	15.57	17.45	21.78	24.82	26.64	25.74	28.29	26.47	25.34	23.42	20.13	20.19	21.74	22.53	23.61	25.46	35.61	26.41	22.85	17.32
61754	0.18	0.15	0.15	0.13	0.14	0.21	0.37	0.49	0.59	0.60	0.61	0.55	0.51	0.47	0.33	0.31	0.26	0.22	0.23	0.45	1.04	0.54	0.29	0.10
	-0.22	-0.13	-0.11	-0.05	-0.09	-0.15	-0.64	-0.81	-0.40	-0.22	-0.98	-0.92	-0.77	-0.68	-0.35	-0.29	-0.26	-0.18	-0.04	-0.09	0.00	0.00	0.00	-0.21
DUNWOD	19.90	18.41	17.65	17.05	18.02	20.85	31.55	34.09	29.87	30.14	32.16	32.31	31.34	27.23	26.50	25.83	27.27	27.23	26.69	29.23	38.96	29.00	25.24	21.69
61760	1.55	1.50	1.43	1.43	1.49	1.71	2.20	2.63	3.18	3.09	3.31	3.05	2.93	2.76	2.35	2.37	2.57	2.68	2.78	3.09	4.39	3.13	2.68	1.82
	-3.00	-1.80	-1.47	-0.74	-1.19	-2.05	-8.58	-7.94	-1.05	-2.12	-2.16	-4.26	-4.35	-2.19	-4.71	-3.88	-3.48	-2.42	-0.59	-1.22	0.00	0.00	0.00	-2.87
GENESE	15.23	14.89	14.53	14.60	15.06	16.90	20.82	23.50	25.24	24.65	26.26	24.82	23.92	22.07	19.34	19.42	20.83	21.58	22.62	24.47	34.43	25.43	21.95	16.61
61753	-0.29	-0.33	-0.29	-0.33	-0.35	-0.31	-0.44	-0.47	-0.46	-0.40	-0.56	-0.43	-0.39	-0.33	-0.37	-0.39	-0.59	-0.69	-0.75	-0.52	-0.14	-0.44	-0.61	-0.56
	-0.17	-0.10	-0.08	-0.04	-0.07	-0.12	-0.49	-0.45	-0.06	-0.12	-0.12	-0.24	-0.25	-0.12	-0.27	-0.22	-0.20	-0.14	-0.03	-0.07	0.00	0.00	0.00	-0.17
H Q	15.00	14.79	14.42	14.57	15.02	16.70	20.25	22.86	24.74	24.03	25.76	24.13	23.24	21.54	18.84	18.98	20.61	21.51	22.70	24.12	33.22	25.04	21.90	16.64
61844	-0.35	-0.33	-0.32	-0.31	-0.32	-0.39	-0.52	-0.66	-0.90	-0.90	-0.94	-0.88	-0.82	-0.73	-0.60	-0.61	-0.62	-0.62	-0.63	-0.80	-1.35	-0.83	-0.65	-0.36
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Day Ahead LMBP-ISO Supply

DEMAND energy
Take charge.

Day Ahead Market Zonal LBMP

--- LBMP $ --- Marginal Cost of Losses --- Marginal Cost of Congestion

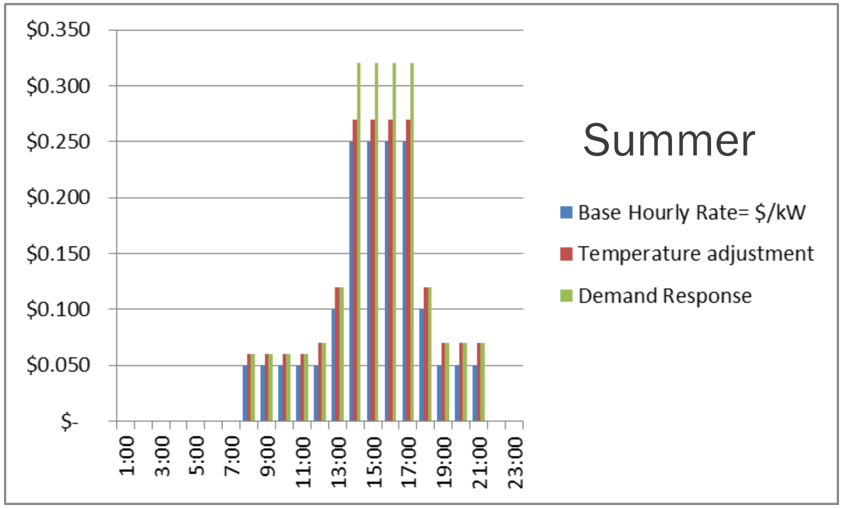
Zonal Prices **Date: 01/09/2016**

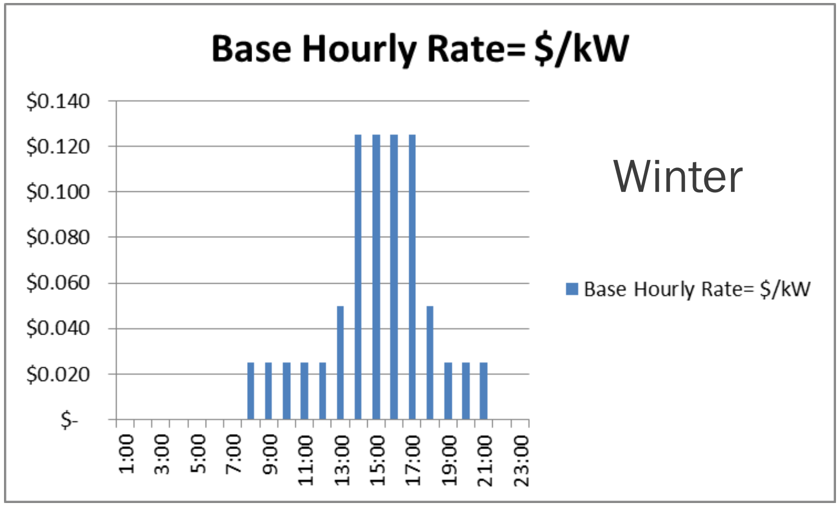
Name PTID	00:00 EST	01:00 EST	02:00 EST	03:00 EST	04:00 EST	05:00 EST	06:00 EST	07:00 EST	08:00 EST	09:00 EST	10:00 EST	11:00 EST	12:00 EST	13:00 EST	14:00 EST	15:00 EST	16:00 EST	17:00 EST	18:00 EST	19:00 EST	20:00 EST	21:00 EST	22:00 EST	23:00 EST
CAPITL	31.90	30.64	28.66	27.98	23.61	25.27	26.86	25.00	27.93	32.00	32.16	32.08	28.12	25.96	26.00	26.22	32.29	44.99	41.54	35.69	32.00	29.34	27.16	26.24
61757	0.31	0.27	0.15	0.17	0.16	0.25	0.24	0.46	0.65	0.85	0.86	0.87	0.79	0.71	0.69	0.71	0.70	1.05	1.06	0.96	0.85	0.66	0.49	0.38
	-26.29	-26.09	-26.09	-25.12	-20.87	-20.67	-22.53	-16.65	-16.84	-18.12	-18.19	-18.19	-14.99	-14.20	-14.61	-14.63	-21.13	-28.88	-24.91	-20.16	-18.03	-18.27	-18.32	-19.28
CENTRL	8.75	7.70	5.84	5.98	5.31	7.05	7.05	10.17	12.66	15.44	15.52	15.48	14.34	12.95	12.67	12.87	13.32	18.93	18.92	17.29	15.54	12.83	10.71	9.16
61754	0.03	0.02	0.01	0.01	0.01	0.00	0.01	0.10	0.04	0.07	0.07	0.12	0.06	0.06	0.08	0.08	0.10	0.12	0.11	0.10	0.08	0.04	-0.02	0.06
	-3.42	-3.40	-3.40	-3.27	-2.72	-2.70	-2.94	-2.17	-2.17	-2.34	-2.35	-2.35	-1.93	-1.83	-1.90	-1.90	-2.75	-3.75	-3.24	-2.62	-2.34	-2.38	-2.38	-2.52
DUNWOD	26.49	25.19	23.12	22.66	19.20	21.03	22.22	21.86	24.94	28.89	29.03	28.97	25.72	23.63	23.55	23.78	28.39	39.62	37.08	32.27	28.95	26.10	23.76	22.45
61760	0.57	0.45	0.24	0.27	0.25	0.44	0.43	0.88	1.27	1.63	1.65	1.68	1.60	1.43	1.38	1.41	1.33	1.88	1.95	1.86	1.67	1.33	1.03	0.72
	-20.62	-20.46	-20.46	-19.70	-16.37	-16.24	-17.70	-13.08	-13.22	-14.22	-14.28	-14.28	-11.77	-11.14	-11.48	-11.49	-16.60	-22.68	-19.57	-15.84	-14.16	-14.35	-14.39	-15.15
GENESE	8.11	7.08	5.26	5.42	4.81	6.48	6.44	9.57	11.89	14.50	14.62	14.61	13.53	12.22	11.97	12.15	12.48	17.79	17.84	16.27	14.68	12.04	10.00	8.56
61753	-0.10	-0.09	-0.04	-0.05	-0.08	-0.16	-0.14	-0.17	-0.40	-0.52	-0.48	-0.40	-0.46	-0.40	-0.34	-0.36	-0.32	-0.47	-0.48	-0.52	-0.43	-0.40	-0.38	-0.16
	-2.90	-2.88	-2.88	-2.77	-2.30	-2.29	-2.49	-1.84	-1.85	-1.99	-2.00	-2.00	-1.65	-1.56	-1.62	-1.62	-2.34	-3.20	-2.76	-2.23	-2.00	-2.02	-2.03	-2.13
H Q	5.17	4.18	2.37	2.63	2.53	4.25	4.00	7.69	10.16	12.66	12.72	12.62	12.00	10.75	10.38	10.57	10.16	14.64	15.13	14.16	12.75	10.13	8.14	6.42
61844	-0.13	-0.10	-0.06	-0.06	-0.06	-0.10	-0.09	-0.21	-0.28	-0.38	-0.38	-0.39	-0.35	-0.31	-0.31	-0.32	-0.30	-0.42	-0.44	-0.41	-0.37	-0.28	-0.21	-0.16
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

New Rate Design for Distribution Charges

Locational Marginal Based Pricing

- Voluntary
- Con Ed Scheduling during critical power events
- Valid 8 am to 10 PM
- Has Forecasted Temperature Adder
- Can Drive Response to Demand Response/Critical Power Events
- Valid Mon-Fri
- Nights and weekends are no-cost





REV Rate Design

- **Based upon the Concepts in the Standby Rate Design**
  - Focused on key operating time periods
    - Monday – Friday
    - 8 AM to 10 PM
- **Contract Demand Charge**
  - Fixed cost component that ensures a base level of revenue for the utility
- **As-used Hourly Demand Charges**
  - Hourly rates from 8 AM to 10 PM.
  - Peak Hours adjusted to the Con Ed Locational Network peaks
  - Summer Rates
  - Winter Rates
- **Monthly Adjustment Clause (MAC)**
  - Changed recently to be kWh based – simplifying the number of variables

Current Standby Rate

Rate IV - General – Large - Standby Service

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 who are not subject to billing under Rate V.

Delivery Charges, applicable to all Customers

Customer Charge $101.09 per month

Demand Delivery Charges

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

1) Applicable to all Customers, except for Station Use by Wholesale Generators:

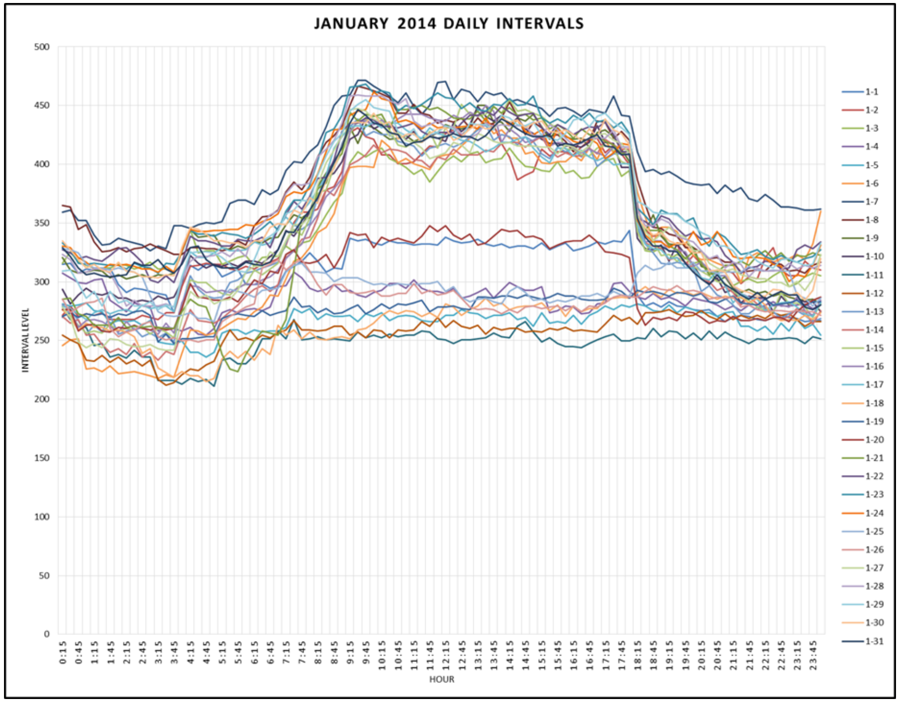
	Low Tension Service	High Tension Service
a) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$6.89 per kW	$5.14 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$0.4434 per kW	$0.4432 per kW
Monday through Friday, 8 AM to 10 PM	$0.9997 per kW	$0.3154 per kW
	$1.4431 per kW	
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$0.7135 per kW	$0.4016 per kW

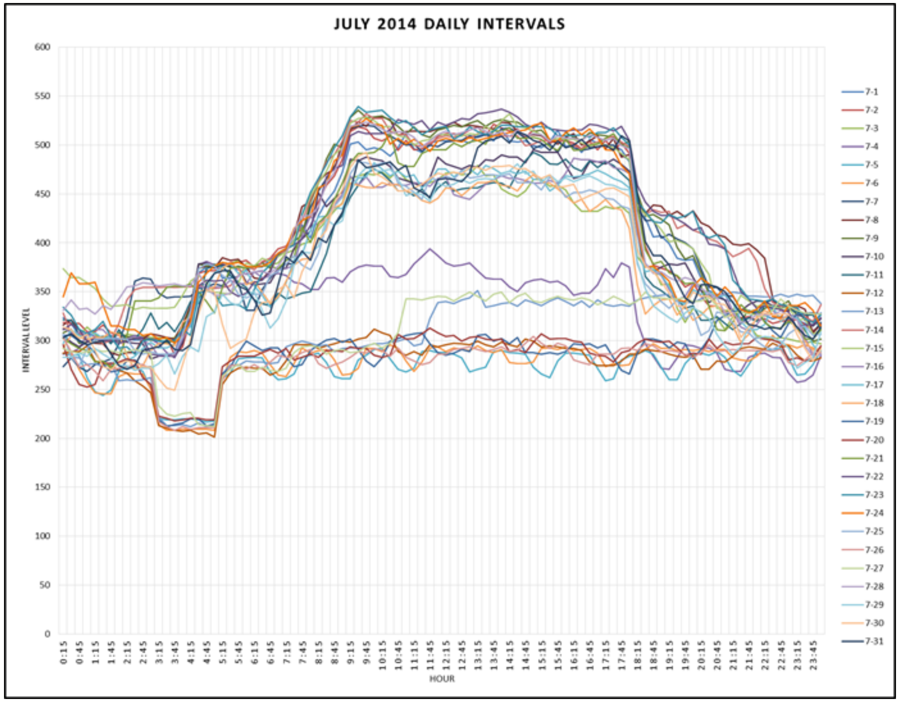
Rate Comparison

Item	SC9 Rate IV	REV LMP+D
Customer Charge	$101.9/Month	$101.9/Month
Contract Demand Delivery Charge	$ 6.89/ kW	$5.00/kW
(Based on 12 Month Rolling Peak)		
Daily As-used Demand Charge		Daily Hourly Sum
Summer	$ 1.4431/kW	$ 1.60 /kW
Winter	$ 0.7135/kW	$ 0.80 /kW
MAC	kWh only	As is in current rate
Demand Enablement		$1200/kW

Summer		Winter		
8:00	$ 0.050		$ 0.025	
9:00	$ 0.050		$ 0.025	
10:00	$ 0.050		$ 0.025	
11:00	$ 0.050		$ 0.025	
12:00	$ 0.050		$ 0.025	
13:00	$ 0.100		$ 0.050	
14:00	$ 0.250		$ 0.100	
15:00	$ 0.250		$ 0.150	
16:00	$ 0.250		$ 0.150	
17:00	$ 0.250		$ 0.100	
18:00	$ 0.100		$ 0.050	
19:00	$ 0.050		$ 0.025	
20:00	$ 0.050		$ 0.025	
21:00	$ 0.050		$ 0.025	
	$ 1.600	/kW	$ 0.800	/kW

Comm. 1 Base Load Profile





Comm. 1 to 4/Rev Rate Comparison

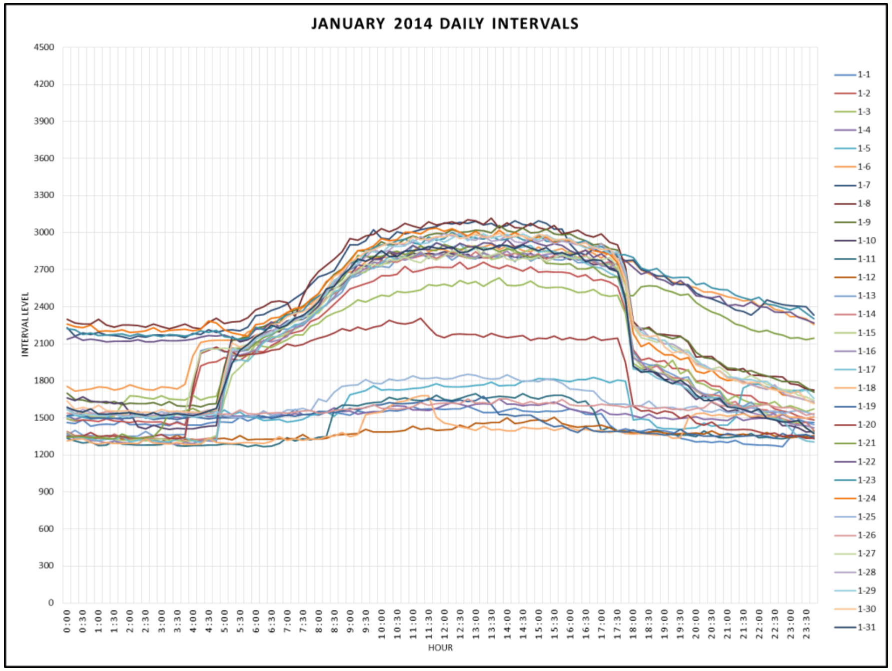
Demand Energy Networks Value Analysis Summary

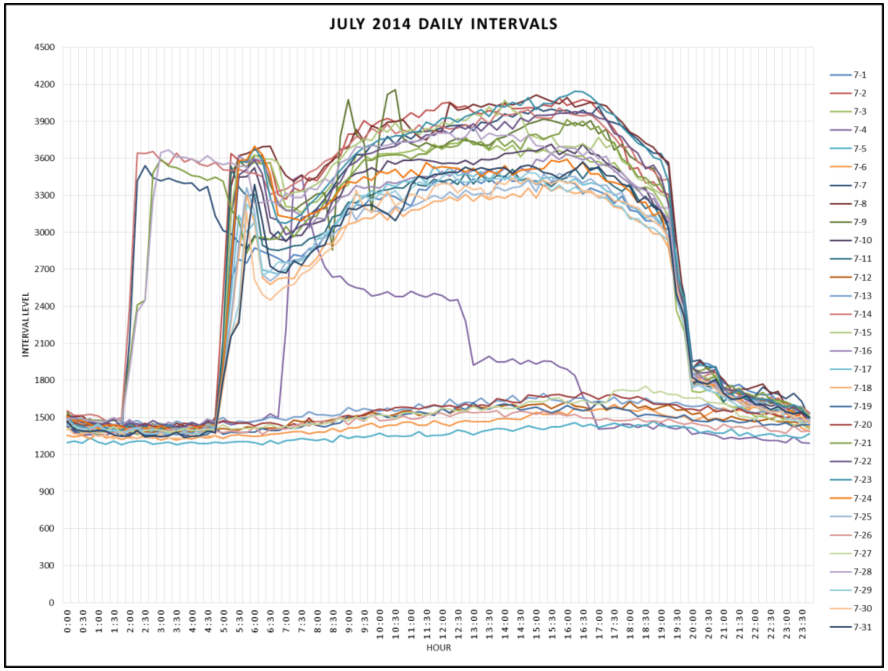
Project	**Commercial 1**

Project Assumptions/Data		
Load Information		
Building Load (Annual kWh)		2,946,175
Building Peak Load (kW)		540
Load Data Source		2014 Interval Data
Baseline:		SC 9, Rate I Supply
Post:		REV Demo
Configuration		
Power Conversion System (kW)		100
Storage Energy Capacity (kWh)		730
Solar System Size (DC kW)		-
Annual Solar or CHP Production		-
Energy Operating Capacity (kWh)		438
Initial System Battery Life (yrs)		7
Cycles per year (yrs)		178
Energy Storage Rack System		8
Model Assumptions		
Energy Escalation Rate		1.0%
Demand Escalation Rate		3.0%
Federal Tax Rate		35.00%
State Tax Rate		8.84%
Roundtrip Efficiency		81.23%
Savings Summary		
Energy Savings Year 1	$	-
Demand Savings Year 1	$	55,799
Total Savings Yr 1	**$**	**55,799**

Project Pro-Forma (20 yr)		
System Price:		
Initial purchase: DEN System (Includes 5yrs MS)	$	395,865
	$	-
Operations and Maintenance yr1	$	-
Subtotal Year 1:	*$*	*395,865*
Extended Costs:		
Battery Upgrades	$	96,000
PCS Upgrades	$	20,000
Managed Services & support (yrs 6-20)	$	97,280
Operations & Maintenance yrs 2-20	$	-
Subtotal Years 2-20:	*$*	*213,280*
Total System Price	**$**	**609,145**
Income -- Credits / Incentive pmts:		
Critical Load Support	$	-
SGIP	$	-
Incentives	$	197,500
Federal Tax Credit (30%)		-
Total Income	$	197,500
Net price	**$**	**411,645**
Savings:		
Supply Charge Savings	$	61,313
Delivery Charge Savings	$	1,499,348
Tax Savings (Expense)	$	224,401
Solar Tax Savings	$	-
Total Savings	$	1,785,062
ROI - $	**$**	**1,373,417**
ROI - %		**225.47%**
IRR: 20-yr		**50.76%**
Payback *(in yrs)*		**2.17**

Comm. 2 Base Load Profile





Comm. 2 Rate Comparison

DEMAND energy
Take charge.

Demand Energy Networks Value Analysis Summary

Project	**Commercial 2**

Project Assumptions/Data		
Load Information		
Building Load (Annual kWh)		17,854,450
Building Peak Load (kW)		4289
Load Data Source		2014 Interval Data
Baseline:		SC 9, Rate II Supply
Post:		REV Demo
Configuration		
Power Conversion System (kW)		500
Storage Energy Capacity (kWh)		3,648
Solar System Size (DC kW)		-
Annual Solar or CHP Production		-
Energy Operating Capacity (kWh)		2,189
Initial System Battery Life (yrs)		7
Cycles per year (yrs)		178
Energy Storage Rack System		40
Model Assumptions		
Energy Escalation Rate		1.0%
Demand Escalation Rate		3.0%
Federal Tax Rate		35.00%
State Tax Rate		8.84%
Roundtrip Efficiency		81.23%
Savings Summary		
Energy Savings Year 1	$	-
Demand Savings Year 1	$	326,890
Total Savings Yr 1	**$**	**326,890**

Project Pro-Forma (20 yr)		
System Price:		
Initial purchase: DEN System (Includes 5yrs MS)	$	1,974,699
	$	-
Operations and Maintenance yr1	$	-
Subtotal Year 1:	*$*	*1,974,699*
Extended Costs:		
Battery Upgrades	$	480,000
PCS Upgrades	$	100,000
Managed Services & support (yrs 6-20)	$	479,178
Operations & Maintenance yrs 2-20	$	-
Subtotal Years 2-20:	*$*	*1,059,178*
Total System Price	**$**	**3,033,877**
Income -- Credits / Incentive pmts:		
Critical Load Support	$	-
SGIP	$	-
Incentives	$	987,500
Federal Tax Credit (30%)		-
Total Income	$	987,500
Net price	**$**	**2,046,377**
Savings:		
Supply Charge Savings	$	371,567
Delivery Charge Savings	$	8,783,662
Incentives (yrs 2-20)	$	-
Tax Savings (Expense)	$	1,119,980
Solar Tax Savings	$	-
Total Savings	$	10,275,209
ROI - $	**$**	**8,228,832**
ROI - %		**271.23%**
IRR: 20-yr		**59.00%**
Payback *(in yrs)*		**2.17**

Commercial Rate Summary

Commercial 1

Building Load (Annual kWh) 2,946,175

Building Peak Load (kW) 540

	Rate 1-4 DRP	Rate 1-4 No Incentives	Rate 1- REV Rate	Rate 1- REV Rate No Incentive
ROI - $	$ 1,276,686	$ 796,686	**$ 1,373,417**	$ 1,175,917
IRR: 20-yr	26.46%	14.30%	**50.76%**	21.68%
Payback *(in yrs)*	3.50	5.58	**2.17**	4.17
Total Savings Yr 1	$ 42,839	$ 42,839	**$ 55,799**	$ 55,799

Commercial 2

Building Load (Annual kWh) 17,854,450

Building Peak Load (kW) 4,289

	Rate 2-5 DRP	Rate 2-5 No Incentives	Rate 2- REV Rate	Rate 2- REV Rate No Incentive
ROI - $	$ 2,872,599	$ 472,599	**$ 8,228,832**	$ 7,241,332
IRR: 20-yr	16.07%	2.54%	**59.00%**	25.59%
Payback *(in yrs)*	4.67	16.08	**2.17**	3.75
Total Savings Yr 1	$ 75,920	$ 75,920	**$ 326,890**	$ 326,890

REV Demo Program Plan

- **RFI Response due March 25 2016**
- **5 MW focus on Commercial /Multifamily Residential Customers**
  - Target Large Property Owners for the Consortium
  - Develop projects across the 4 CSRP peak time periods
  - Seek Letters of Intent for RFI Response
- **Distributed Across Con Ed Stressed Networks to address the 4 CSRP time periods**
- **Begin Installation in June 2016**
- **Look for opportunities to combine with Solar installations**
- **Develop Methodology for determining LMP+D variables**
- **Smart meters are included in the installation costs**
- **Develop Billing method**
- **Develop Market Based Earnings mechanisms to prove how Con Ed can generate revenue as a Distribution System Platform Provider**

Appendix B - NY-BEST Comments on the Value of DER (LMP+D)
DER Products Matrix

Product Categories	DER Product	Distribution System Planning Benefits	Distribution System Operations Benefits	Public Policy Benefits	Technology Examples
Energy (modification to base load)	Energy (TOU Rates, Nodal factors)	Improved asset utilization, Wholesale market efficiency, Reliable baseload DG, Reduced hedging and gas capacity procurement, Optimize T&D investment	Reduced line loading, Reduced losses, Local utilization, Improved load factor, Local optimization, Avoided Fuel Cost, Avoided central station O&M, Increased flexibility, Lower overall energy cost,	localization of renewable resources,reduced emissions, improved system efficiency, Fuel diversity, Lower energy prices,	DG (e.g., PV, fuel cells, CHP) , Energy Storage, CHP
	Permanent Load Shift/Reduction	Improved asset utilization, Wholesale market efficiency, Reliable baseload DG, Reduced hedging and gas capacity procurement, Optimize T&D investment	Reduced line loading, Reduced losses, Local utilization, Improved load factor, Local optimization, Avoided Fuel Cost, Avoided central station O&M, Increased flexibility, Lower overall energy cost,	localization of renewable resources,reduced emissions, improved system efficiency, Fuel diversity, Lower energy prices,	DG (e.g., PV, fuel cells, CHP), Energy Efficiency, CHP
Power (modification to peak loads)	Capacity - (DER output offsetting Generation, Transmission, and Distribution components)	Improved asset utilization and load factor, "net" load duration curve planning (Consideration of upstream and localized asset costs.), Facilitates high renewable penetration, Reduce T&D investment, feeder overload relief and site specific congestion relief	asset utilization, less overcapacity, increased system efficiency, improved local quality, system stability, lower customer bills, Improved reliability, Lower O&M, Lower Generation and T&D investment	Less over capacity, lower infrastructure costs, improved system efficiency, reliability. Increased renewables, Lower emissions, more effective planning, can increase resiliency	DG, Energy Storage, CHP, efficiency
	Demand Response/ Peak Management	Improved asset utilization and load factor, "net" load duration curve planning (Consideration of upstream and localized asset costs.), Facilitates high renewable penetration, Reduce T&D investment, feeder overload relief and site specific congestion relief	asset utilization, less overcapacity, increased system efficiency, improved local quality, system stability, lower customer bills, Improved reliability, Lower O&M, Lower Generation and T&D investment	Less over capacity, lower infrastructure costs, improved system efficiency, reliability. Increased renewables, Lower emissions, more effective planning, can increase resiliency	Demand Management (dispatchable or price sensitive), DG, Energy Storage, CHP
	Power Firming (Nodal Firming)	stable nodes do not drive additioanal regulation and reserve requirements	Reduced system demand for regulation and spinning reserve	more effective planning, less over capacity, lower infrastructure costs, improved system efficiency	Energy Storage, Smart Inverters, Demand Management
	Ramp Rate or "Flexible Capacity"	stable nodes do not drive additional regulation and reserve requirements	Reduced system demand for regulation and spinning reserve	more effective planning, less over capacity, lower infrastructure costs, improved system efficiency	Energy Storage, Smart Inverters, Demand Management

Grid Support (Ancillary) Services	Frequency Response	local optimization of services reduce tranmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Incentivizes fast resources to manage frequency, improve system efficiency	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Frequency Regulation	local optimization of services reduce transmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Minimizes the quantify of operating reserves needed; Improves system efficiency	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Spinning Reserves	local optimization of services reduce tranmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Minimizes the quantity of operating reserves needed	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Non-Spinning Reserves	local optimization of services reduce tranmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Minimizes the quantify of operating reserves needed	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Power Factor Correction	Improved reliability and power quality, asset utilization, efficiency	Improved reliability and power quality, asset utilization, efficiency	Improved reliability and power quality, asset utilization, efficiency	Energy Storage, Smart Inverters, DG, CHP, FACTS, Capacitor banks
	Voltage Support	Increased PV penetration levels, reactive/real power support, better power quality	Improved reliability and power quality	Increased PV penetration levels, reduced emissions, better power quality	Energy Storage, Smart Inverters, DG, CHP, FACTS, Capacitor banks
	Enhanced System Control and Dispatch	Avoided T&D capital investments	Suppresses wholesale prices, improved reliability and blackstart, system balancing, increased system efficiency	Reduced emissions, reduced fuel consumption, lower consumer costs	Remote sensing, Meters, Energy monitoring and management technology, Energy Storage, EV Charging Stations
Contingency/Planning	Resource Adequacy	Improved asset utilization, "net" load duration curve planning	asset utilization, less overcapacity, improved local quality	more effective planning, less over capacity, lower infrastructure costs	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Online Backup Power	Improved reliability and power quality	Improved reliability and power quality	Improved reliability and power quality; reduced emissions	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Demand Response	Improved asset utilization,	asset utilization, less overcapacity, improved local quality	reliability, power quality, emergency support	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Black Start	Improved reliability and power quality	Improved reliability and power quality	improved resiliancy, reliability, reduced emissions, reduced recovery time	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Emergency Power Islands	Improved recovery	Blackstart, Improved response to emergencies	Public health and safety benefits, resiliency, avoided economic costs	Microgrid, DG, CHP, Energy Storage, Fuel Cells

Energy Products

Product Categories	DER/Customer Product	Distribution System Planning Benefits	Distribution System Operations Benefits	Public Policy Benefits	Technology Examples
Energy (modification to base load)	Energy (TOU Rates, Nodal factors) Energy represents the energy output of any eligible DER that is not used for individual customer's self-supply purposes, or is generating in excess of customer need. This resource would be exported to the grid, not used to power on-site equipment or appliances.	Improved asset utilization, Wholesale market efficiency, Reliable baseload DG, Reduced hedging and gas capacity procurement, Optimize T&D investment	Improved load factor, Reduced line loading, Reduced losses, Local utilization, Reduced system complexity, Local optimization, Avoided Fuel Cost, Avoided central station O&M, Increased flexibility, Lower overall energy cost,	localization of renewable resources,reduced emissions, improved system efficiency, Fuel diversity, Lower energy prices,	DG, Energy Storage, PV, CHP, Fuel Cells
	Permanent Load Shift/Reduction Permanent load reductions in all hours or selected hours, or permanent load shifting	Improved asset utilization, Wholesale market efficiency, Reliable baseload DG, Reduced hedging and gas capacity procurement, Optimize T&D investment	Improved load factor, Reduced line loading, Reduced losses, Local utilization, Reduced system complexity, Local optimization, Avoided Fuel Cost, Avoided central station O&M, Increased flexibility, Lower overall energy cost,	localization of renewable resources,reduced emissions, improved system efficiency, Fuel diversity, Lower energy prices,	DG, Energy Efficiency, CHP, Energy Storage, Fuel Cells

Questions/Issues to be resolved:

1) how this will be different from wholesale energy product, ie. How is locational value considered?
2) Realizing value for avoided T&D infrastructure investments depends on location and requires analysis.
3) Permanence of load reduction. Some suggest considering as DR
4) Ensure that DERs are cleaner than central station plants
5) Intermittency of some DER sources - how to incorporate unpredictable, intermittent sources into DSPP model

Power - Capacity and Peak Load Modifications

Product Categories	DER/Customer Product	Distribution System Planning Benefits	Distribution System Operations Benefits	Public Policy Benefits	Technology Examples
Power (modification to peak loads)	Capacity - (DER output offsetting Generation, Transmission, and Distribution components)	Improved asset utilization and load factor, "net" load duration curve planning (Consideration of upstream and localized asset costs.), Facilitates high renewable penetration, Reduce T&D investment, feeder overload relief and site specific congestion relief	asset utilization, less overcapacity, increased system efficiency, improved local quality, system stability, lower customer bills, Improved reliability, Lower O&M, Lower Generation and T&D investment	Less over capacity, lower infrastructure costs, improved system efficiency, reliability. Increased renewables, Lower emissions, more effective planning, can increase resiliency	DG, Energy Storage, CHP, Fuel Cells
	Demand Response/ Peak Management	Improved asset utilization and load factor, "net" load duration curve planning (Consideration of upstream and localized asset costs.), Facilitates high renewable penetration, Reduce T&D investment, feeder overload relief and site specific congestion relief	asset utilization, less overcapacity, increased system efficiency, improved local quality, system stability, lower customer bills, Improved reliability, Lower O&M, Lower Generation and T&D investment	Less over capacity, lower infrastructure costs, improved system efficiency, reliability. Increased renewables, Lower emissions, more effective planning, can increase resiliency	Demand Response (dispatchable or price sensitive), DG, Energy Storage, CHP
	Power Firming (Nodal Firming)	stable nodes do not drive additioanal regulation and reserve requirements	Reduced system demand for regulation and spinning reserve	more effective planning, less over capacity, lower infrastructure costs, improved system efficiency	Energy Storage, Smart Inverters, Demand Reponse
	Ramp Rate or "Flexible Capacity"	stable nodes do not drive additional regulation and reserve requirements	Reduced system demand for regulation and spinning reserve	more effective planning, less over capacity, lower infrastructure costs, improved system efficiency	Energy Storage, Smart Inverters, Demand Reponse

Questions/Issues to be resolved:
1) how this will be different from wholesale capacity product, ie. How is locational value considered?
2) qualification of reliability of asset
3) Generation, Transmission, and Distribution components should all be considered for pricing

Grid Support

Product Categories	DER/Customer Product	Distribution System Planning Benefits	Distribution System Operations Benefits	Public Policy Benefits	Technology Examples
Grid Support (Ancillary) Services	Frequency Response	local optimization of services reduce tranmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Incentivizes fast resources to manage frequency, improve system efficiency	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Frequency Regulation	local optimization of services reduce transmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Minimizes the quantify of operating reserves needed; Improves system efficiency	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Spinning Reserves	local optimization of services reduce tranmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Minimizes the quantity of operating reserves needed	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Non-Spinning Reserves	local optimization of services reduce tranmission assets and contingency needs	Increased distribution level system scope and revenue	Additional revenue capability to offset opex - Minimizes the quantify of operating reserves needed	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Power Factor Correction	Improved reliability and power quality, asset utilization, efficiency	Improved reliability and power quality, asset utilization, efficiency	Improved reliability and power quality, asset utilization, efficiency	Energy Storage, Smart Inverters, DG, CHP, FACTS, Capacitor banks
	Voltage Support	Increased PV penetration levels, reactive/real power support, better power quality, savings in substations	Improved reliability and power quality	Increased PV penetration levels, reduced emissions, better power quality	Energy Storage, Smart Inverters, DG, CHP, FACTS, Capacitor banks
	Enhanced System Control and Dispatch	Avoided T&D capital investments	Suppresses wholesale prices, improved reliability and blackstart, system balancing, increased system efficiency	Reduced emissions, reduced fuel consumption, lower consumer costs	Remote sensing, Meters, Energy monitoring technology, Energy Storage, EV Charging Stations

Contingency/Planning

Product Categories	DER/Customer Product	Distribution System Planning Benefits	Distribution System Operations Benefits	Public Policy Benefits	Technology Examples
Contingency/Planning	Resource Adequacy	Improved asset utilization, "net" load duration curve planning	asset utilization, less overcapacity, improved local quality	more effective planning, less over capacity, lower infrastructure costs	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Online Backup Power	Improved reliability and power quality	Improved reliability and power quality	Improved reliability and power quality; reduced emissions	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Emergency Demand Response (may be redundant to above DR)	Improved asset utilization,	asset utilization, less overcapacity, improved local quality	resiliency, power quality, emergency support	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Black Start	Improved reliability and power quality	Improved reliability and power quality	improved reliancy, reliability, reduced emissions, reduced recovery time	Energy Storage, Smart Inverters, DG, CHP, Demand Reponse
	Emergency Power Islands	Improved recovery	Blackstart, Improved response to emergencies	Public health and safety benefits, avoided economic costs of outages	Microgrid, DG, CHP, Energy Storage, Fuel Cells