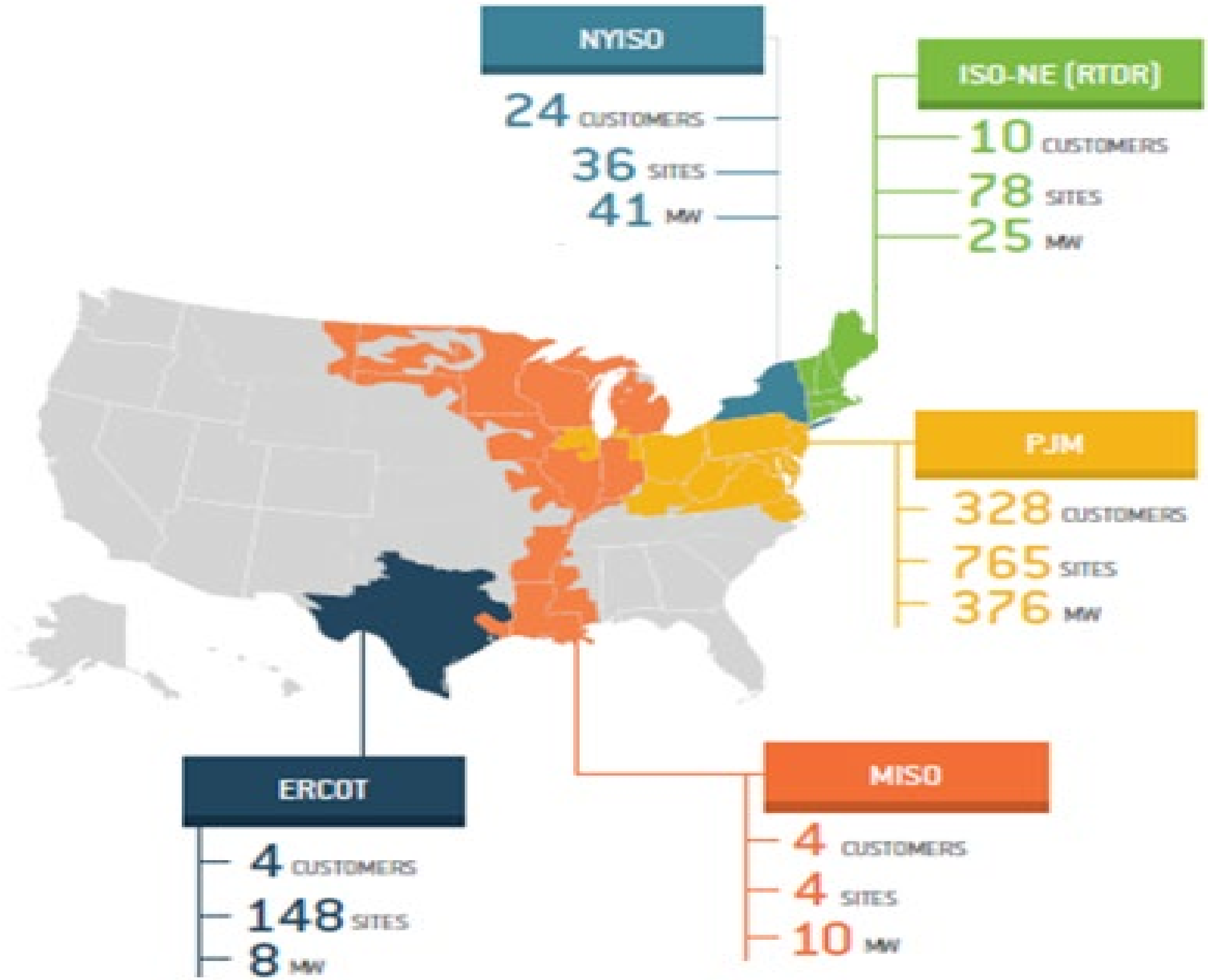
Direct Energy Business

DEMAND RESPONSE

Markets We Serve



Demand Response

What Is Demand Response? Demand Response is a type of load management program that pays participants to reduce their electrical usage during periods of peak demand across the system

Reasons to enroll in Demand Response with Direct Energy	
	1) Customer facing web platform - RT data and customer reports
	2) Bundling of electricity with Demand Response – tax savings
	3) No upfront cost – limited risk
	4) Monthly Payments
	5) Footprint ; #1 natural gas and power supplier; serve ~ 400 DR customers

PJM Product Comparison

Requirement	(Today) Limited DR (15/16 – 17/18)	(Today) Extended Summer DR (15/16 – 17/18)	(Today) Annual DR (15/16 – 17/18)	(CP) Base Capacity DR (18/19 & 19/20 DY only)	(CP) Capacity Performance DR (16/17 DY & beyond)
Availability	Non-NERC holiday weekday, June – Sept	June – Oct & May	Any day during DY*	June - Sep	Any day during DY*
Maximum Number of Interruptions	10 interruptions	Unlimited	Unlimited	Unlimited	Unlimited
Hours of Day Required to Respond (Hours in EPT)	12:00 PM – 8:00 PM	10:00 AM – 10:00 PM	June – Oct & May: 10 AM – 10 PM Nov. – April: 6 AM- 9 PM	10:00 AM – 10:00 PM	June – Oct. & May: 10 AM – 10 PM Nov. – April: 6 AM- 9 PM
Maximum Duration of Interruption	6 Hours	10 Hours	10 Hours	10 Hours	June – Oct : 12 hours Nov – April: 15 hours

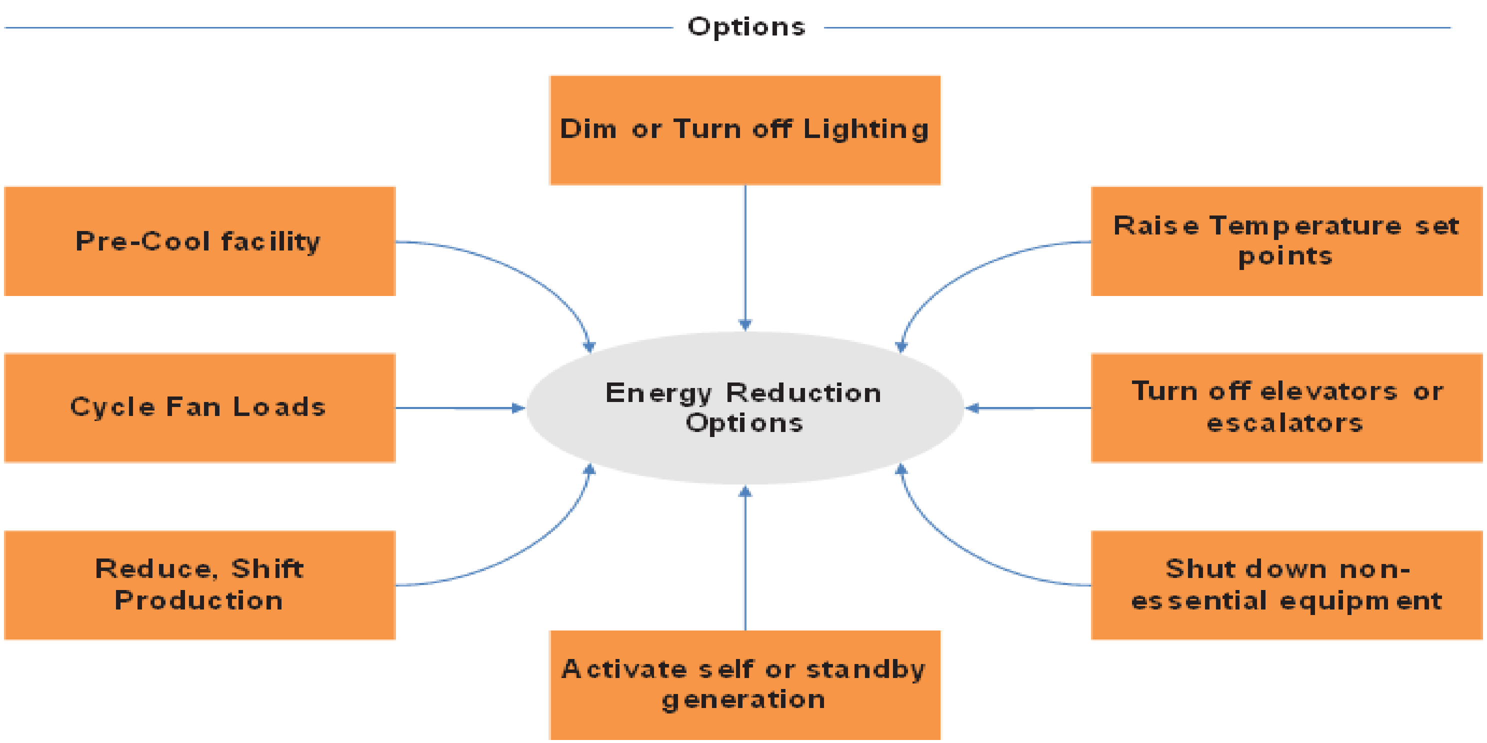
Rule Summary – PJM Emergency Load Response

Program Feature	Description
Program Period(s)	**June 1 – May 31**
Eligibility	Most of PJM territory is eligible to participate (some municipalities and states have restrictions)
Payment Basis	Capacity payment (prices determined in 3-yr forward auctions) – zonal capacity rate * enrolled capacity Energy payment (events only) – RT LMP * hourly reduction
Aggregation	Primarily dispatched by zone
Enrollment	**2/14** Deadline for new customers requiring a data logger installation for interval data **4/15** Deadline for all new contracts
Market Offers (if applicable)	Currently, no energy market offer requirement .
Metering	1-hour interval metering required
Testing Requirements	1 hour of testing required if not actual events called
Event Dispatch	30 Min Notification (Exceptions granted based on **physical** need for either 1 hour or 2 hours) Dispatch limits Base DR: June-Sept, 10am-10pm, unlimited # of interruptions, up to 10-hr duration Capacity Performance: Any day during the DY, unlimited
Performance	Base DR: roughly PLC-FSL, underperformance reduces revenue Capacity Performance: same as above from June-Oct & May, then economic baseline or winter PLC for remaining months, , underperformance reduces revenue, extreme underperformance could lead to out-of-pocket penalties.
Payment	Capacity payments made monthly, Energy payments only earned for actual events (no tests)Description of payment basis (test/event results, price, share, etc.) Capacity payment begins in June, adjusted based on actual performance accordingly
Use of Generation	Customer is responsible for its compliance with all federal, state and local requirements for utilizing generators for DR programs

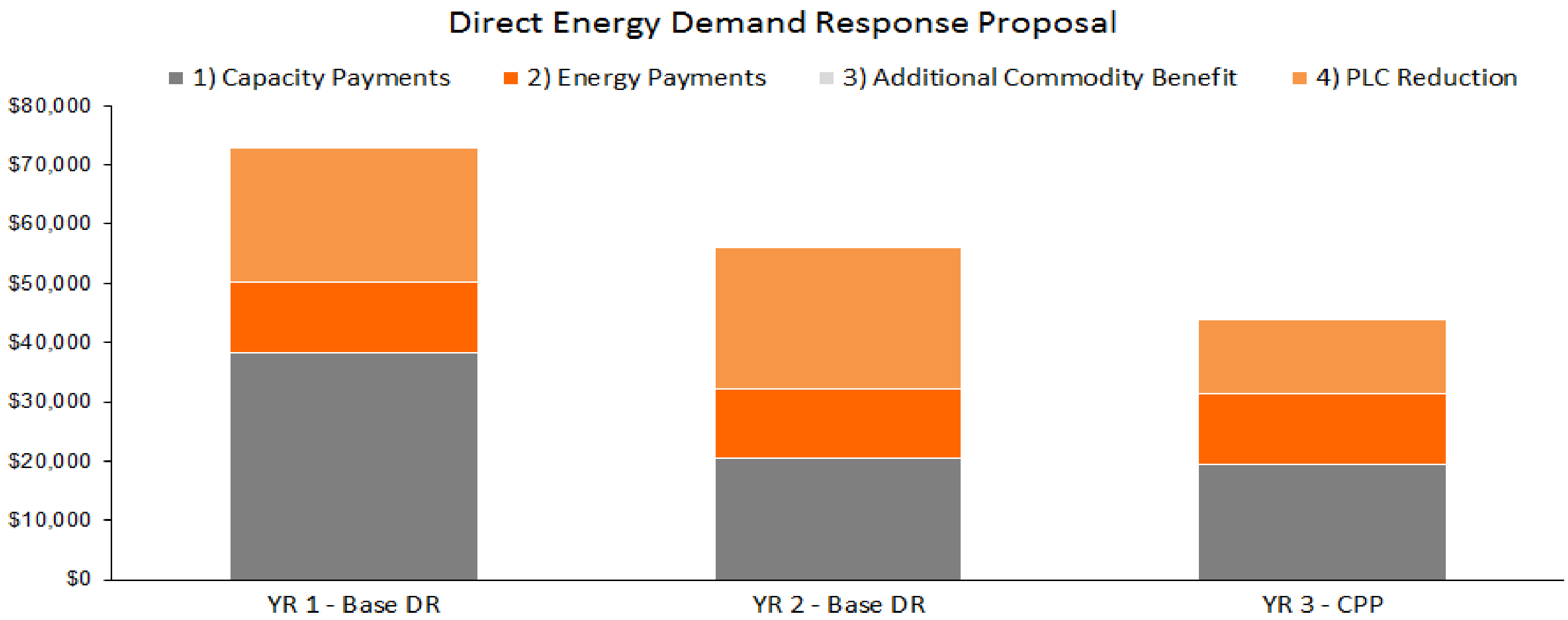
Split Guidelines & Curtailment Options

- Curtailment Amount & Minimum DE split
  - 100kW - 500kW = 25%
  - 500kW - 1000kW = 20%
  - 1000kW - 3000kW = 15%

- Minimum 3 Year Term Preferred

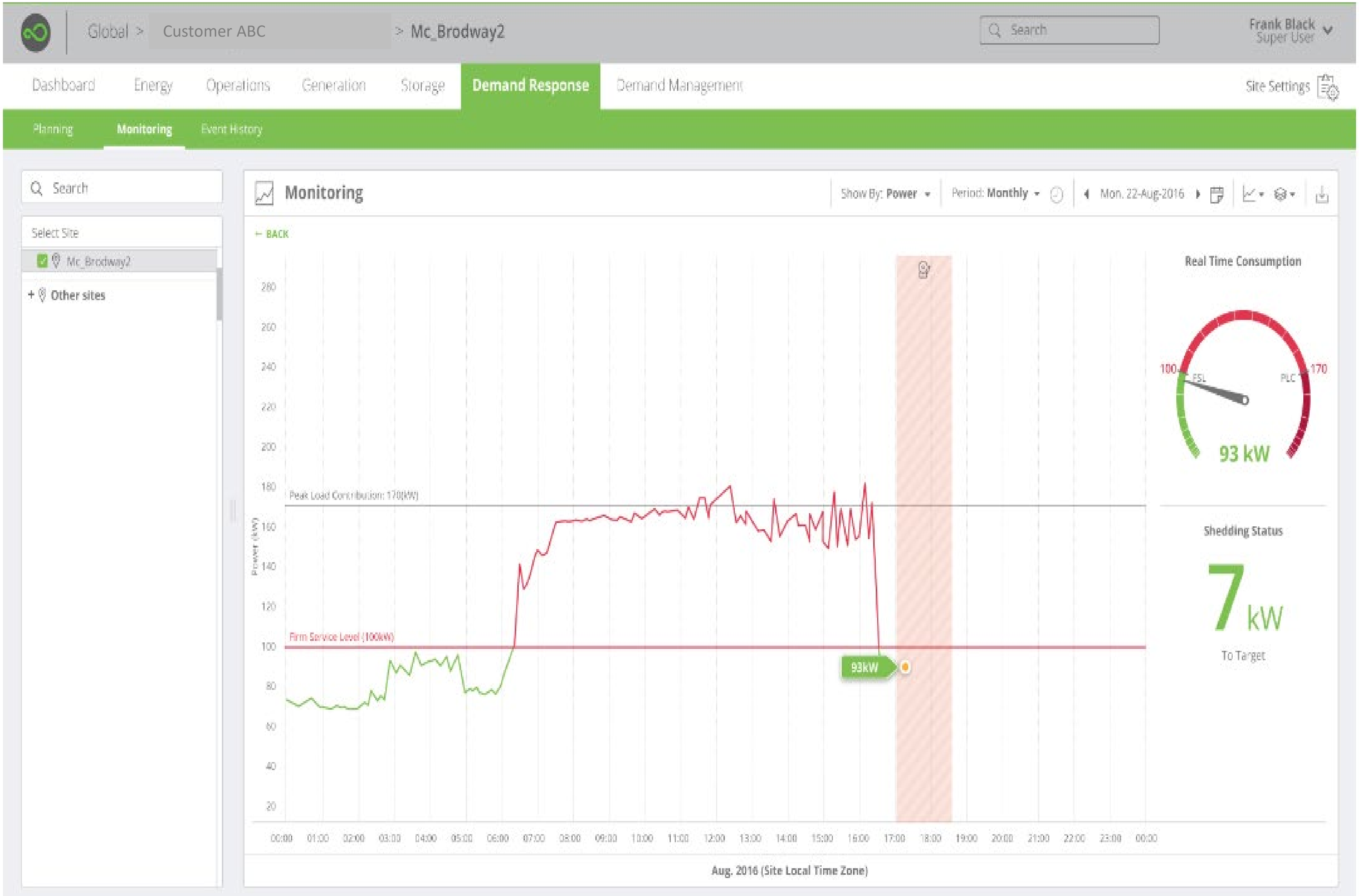


Demand Response Proposal



	Potential Demand Management Revenues for 3 Yrs -1000 kw				
	1) Capacity Payments	2) Energy Payments	3) Additional Commodity Benefit	4) PLC Reduction	Annual Revenues
YR 1 - Base DR	$38,320	$11,834	$0	$22,591	$72,744
YR 2 - Base DR	$20,440	$11,834	$0	$23,664	$55,938
YR 3 - CPP	$19,553	$11,834	$0	$12,533	$43,920
Total	**$78,313**	**$35,501**	**$0**	**$58,788**	**$172,602**

Demand Response - Monitoring



Peak Demand Report

PJM - Peak Demand Report

Friday, July 21, 2017

Summer 2017 Peak Demand to Date

Date	Hour Ending	Peak Demand
7/19/2017	18	146,566
7/20/2017	17	146,103
6/12/2017	18	140,945
7/18/2017	18	139,419
6/13/2017	17	138,603

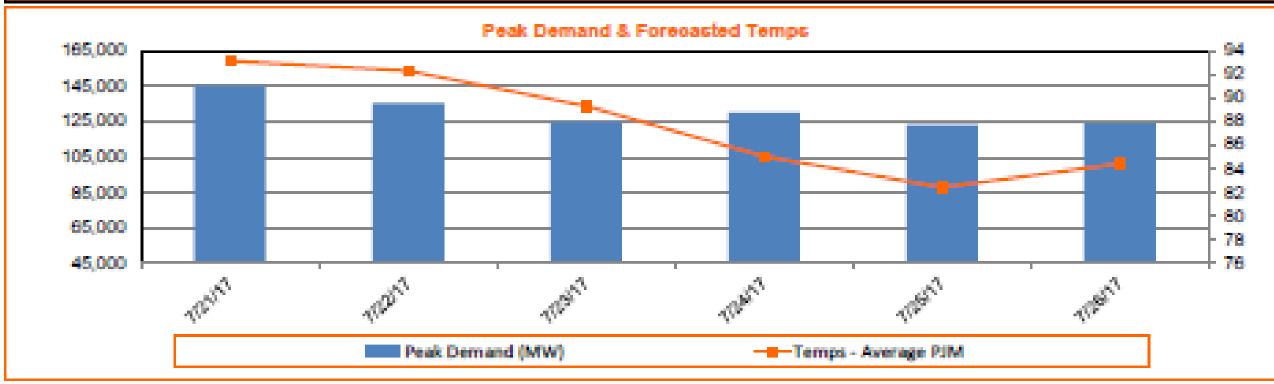
Summer 2016 PJM 5 Coincident Peaks (5CP)

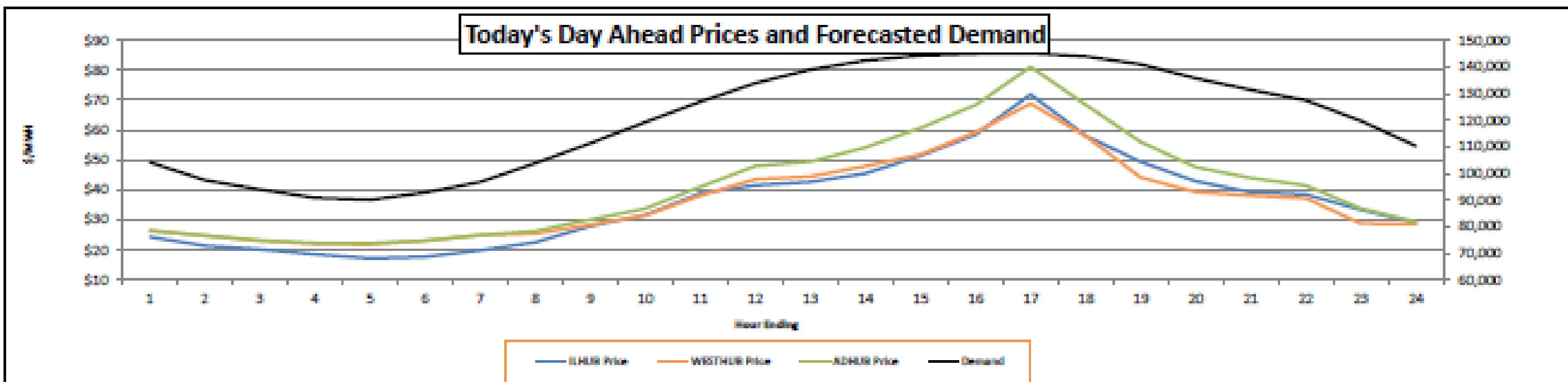
Date	Hour Ending	Demand
8/11/2016	16	151,945
7/25/2016	16	150,931
8/12/2016	16	146,889
7/27/2016	17	144,543
8/10/2016	17	143,357

Summer 2015 PJM 5 Coincident Peaks (5CP)

Date	Hour Ending	Demand
7/28/2015	17	143,496
7/20/2015	17	142,897
7/29/2015	17	142,291
9/3/2015	17	141,228
8/17/2015	15	139,468

Date (Forecasted)	Hour Ending	Peak Hour (Eastern)	Peak Demand MW (Forecasted)	% of 2017 Highest Demand to date	% of 2016 Highest CP Demand	% of 2015 Highest CP Demand	Forecasted High Temperatures: PJM Average
Fri, Jul 21, 2017	17	4:00 pm - 4:59 pm	145,206	99%	96%	101%	93
Sat, Jul 22, 2017	17	4:00 pm - 4:59 pm	135,342	92%	89%	94%	92
Sun, Jul 23, 2017	17	4:00 pm - 4:59 pm	124,501	85%	82%	87%	89
Mon, Jul 24, 2017	17	4:00 pm - 4:59 pm	130,263	89%	86%	91%	85
Tue, Jul 25, 2017	17	4:00 pm - 4:59 pm	122,966	84%	81%	86%	82
Wed, Jul 26, 2017	18	5:00 pm - 5:59 pm	123,784	84%	81%	86%	84





PLC Reduction Analysis

Customized for:

Customer ABC

Capacity Prices - PPL	kW-month	
Estimated Capacity Rate for Baseline (Jun 2017 - May 2018):	$ 4.62	
Estimated Capacity Rate for Reduction (Jun 2019 - May 2020):	$ 2.98	
Baseline: (Jun 2017 - May 2018)		
Current PLC:	5,473	kW
Annual Capacity Cost:	$303,608	
10 % PLC Reduction: (Jun 2019 - May 2020)		
PLC with 10 % Reduction	4,926	kW
Annual Capacity Cost:	$176,076	
Year over Year Change	($127,532)	
Cost Avoided	($19,564)	

Demand Response Qualification Process

- Have you ever participated in a DR program?

- Is your peak demand greater than 500 kW?
    - Can you shut down a process that results in a 250 kW drop?
    - How quickly can you shut down the process?

- Do you have emergency/backup generator to use for DR purposes?
    - Note: Ensure it meets federal/state requirements.

- Interested in consolidating commodity and DR under one provider?

- Do you have a Curtailment Strategy Plan? What can you shut down?

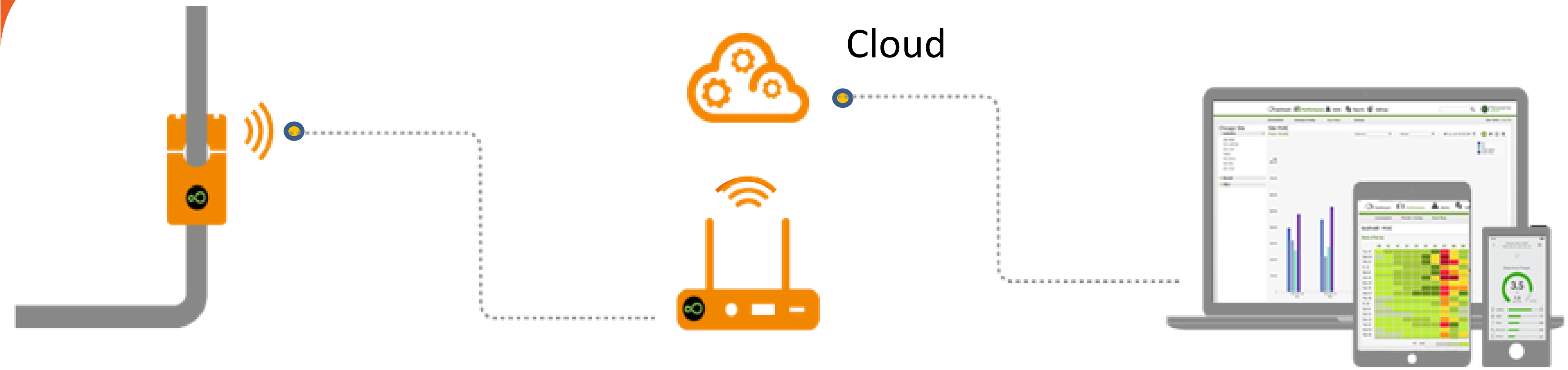
- BMS capability for curtailment?

Information needed to begin proposal

- Customer Legal Name
- Customer Contract Information
- Account Numbers
- Utility
- Estimated Load Curtailment and/or PLC
- Annual Usage
- Current Commodity Customer (Y/N)

DR & Panoramic - Planning

Panoramic – Device Level Monitoring



SENSOR

- Non-Invasive
- Self-Powered
- Wireless
- No Disruption

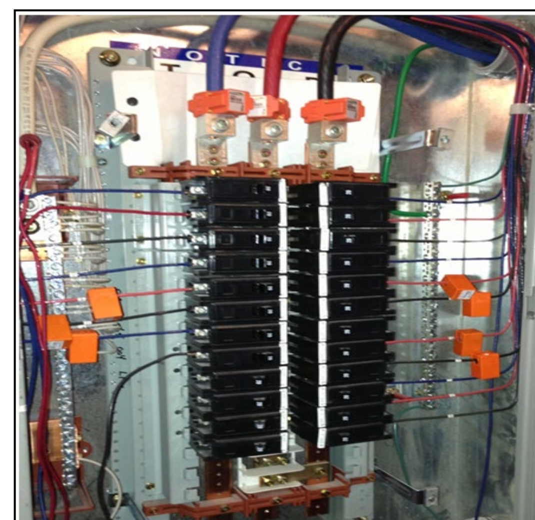
BRIDGE

- Plug & Play
- Cellular or Wi-Fi
- Up to 250 sensors

DASHBOARD/MOBILE

- Executive Reports
- Real-Time Alerts
- Online Analytics
- Device Analyzer

Portfolio of Sensors & Meters



BEFORE: Parking Lot Lighting

8 parking lot light circuits on = $1.26 / Hour

Off hours/weekend waste =

(14 hours * 5 Days * $1.26) + (24 Hours * 2 Days * $1.26) = $148.20 Week

Daily =	$21.17
Weekly =	$148.20
Monthly =	$592.80
Annual =	$7,113.60

AFTER: Parking Lot Lighting

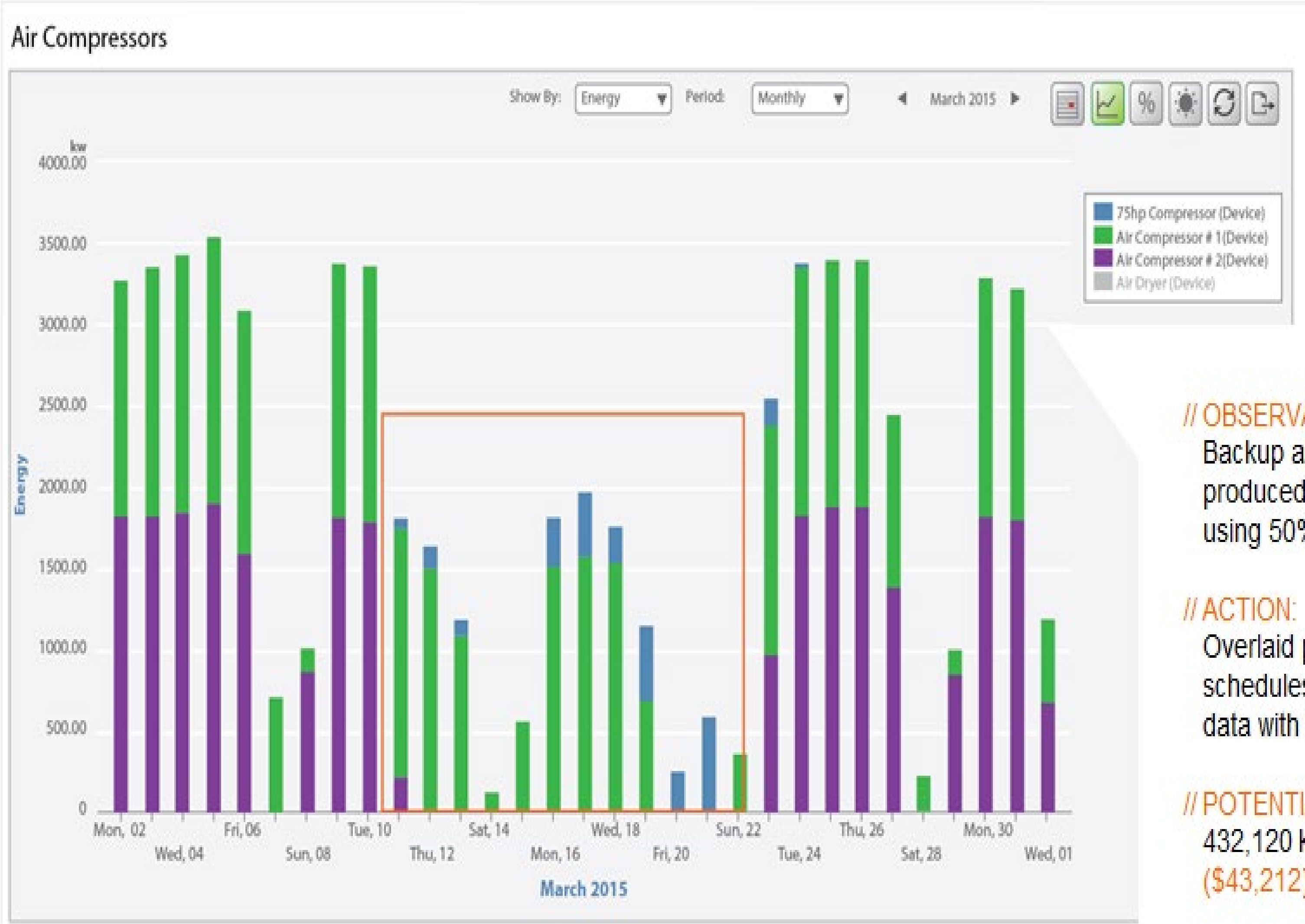
Building Management System (BMS) corrected

Real-time text/email alerts scheduled with 48-hour trigger

Data verified through Panoramic Power dashboard

Savings realized immediately

Air Compressors



// OBSERVATIONS:

Backup air compressor produced at the same level using 50% less kWh.

// ACTION:

Overlaid production schedules and verified data with facility engineers

// POTENTIAL SAVINGS:

432,120 kWh/year

($43,212)

APPENDIX

NYISO

Rule Summary – NYISO SCR

Program Feature	Description
Program Period(s)	Summer Capability Period: May – October | Winter Capability Period: November – April
Eligibility	Minimal zonal obligation of 100 kW
Payment Basis	Capacity Prices are based on monthly auction clearing price Energy Prices are based on LMP
Aggregation	Based on zones from A through K
Enrollment	Enrollment deadline for a particular month is always the first week of the prior month. Monthly enrollments are allowed at any point.
Metering	Must have an utility interval meter or DE data logger
Testing Requirements	1 test each capability period unless an event occurs. Summer test window: August 15^{th} – September 7^{th} Winter test window: February 15^{th} – March 7th
Event Dispatch	Minimum of 21 hours day ahead notification & a minimum of 2 hours day of confirmation Must perform for 4 consecutive hours
Performance	Must meet CMD (Committed Maximum Demand) level. Failure to meet the obligation will result in 50% penalty of shortfall.
Payment	Settlements are done monthly based on auction clearing price
Use of Generation	Must meet EPA's RICE NESHAP emission criteria and be certified to perform in DR

Rule Summary – ConEd DLRP

Program Feature	Description
Program Period(s)	Summer Capability Period Only : May – September
Eligibility	Must be able to reduce load with two hours lead time & Program must be available in the facility's area. Other than ConEd and ORU, this program is not available in most places.
Payment Basis	Capacity Prices and Energy prices are set by tariff based on the utilities and territories.
Aggregation	Based on utility territory networks
Enrollment	Enrollment deadline is April 1st for May 1st start and May 1st for June 1st start. Cannot get in the reservation program beyond May 1st until next year.
Metering	Must have an utility interval meter as the settlements are conducted by the utilities
Testing Requirements	1 test each capability period unless an event occurs. Typically the one hour test occurs in June or July depending on the weather.
Event Dispatch	2 Hours lead time
Performance	Performance is based on the delta between load at the site during test/event and the baseline that's calculated based on the site's load in the previous eligible top 5 usage hours.
Payment	Monthly settlements are done based on performance factor and tariff based price
Use of Generation	Must meet EPA's RICE NESHAP emission criteria and be certified to perform in DR

Rule Summary – ConEd CSRP

Program Feature	Description
Program Period(s)	Summer Capability Period Only : May – September
Eligibility	Must be able to reduce load during a call window set by the utilities. Call windows depend on when the facility's territory is predicted to peak. Call windows include 11 – 3PM, 2 – 6 PM, 4 – 8 PM & 7 – 11PM.
Payment Basis	Capacity Prices and Energy prices are set by tariff based on the utilities and territories.
Aggregation	Based on utility territory networks
Enrollment	Enrollment deadline is April 1st for May 1st start and May 1st for June 1st start. Cannot get in the reservation program beyond May 1st until next year.
Metering	Must have an utility interval meter as the settlements are conducted by the utilities
Testing Requirements	1 test each capability period unless an event occurs. Typically the one hour test occurs in June or July depending on the weather.
Event Dispatch	21 hours day ahead notification and 2 hours day of confirmation.
Performance	Performance is based on the delta between the load at the site during test/event and the baseline that's calculated based on the site's load in the previous eligible top 5 usage hours.
Payment	Monthly settlements are done based on performance factor and tariff based price
Use of Generation	Must meet EPA's RICE NESHAP emission criteria and be certified to perform in DR. Cannot use diesel generator to reduce load in certain areas if an utility generator is within the vicinity

NEW ENGLAND

Rule Summary – RTDR

Program Feature	Description
Program Periods	**Annual Capability Period:** June 1 through May 31 **Summer Performance:** June through August , **Summer Shoulder:** Sept – Nov, April & May **Winter Performance:** Dec & Jan. **Winter Shoulder:** Feb & March
Eligibility	Commercial and Industrial Clients usually with a curtailable load of 100kW +
Payment Basis	3 year forward market auction, other auctions to balance position throughout the year. Revenue earned for both **CAPACITY & ENERGY**
Aggregation	Assets are aggregated into "resources" (pools of assets) predominantly by state. (see map on following slide)
Enrollment	Enrollment months: June to August, December & January ** approx. 2 months to enroll asset
Market Offers	Price Responsive Demand (PRD) will require daily submittal of both Day-Ahead & Real-Time offers. If offers are competitive, asset will be required to curtail/ run generator. Failure to participate will result in monetary penalties.
Metering	Required 5 minute interval data meter to be installed on all assets to participate per ISO-NE rules.
Testing Requirements	One-hour test in June & December, Notification ½ hour prior to audit start time
Event Dispatch	Event duration is decided by ISO-NE, Notification ½ prior to event start time
Performance	"Mean 10 of 10" baseline calculation
Payment	Customers receive checks monthly. See "Rhythm & Cadence" Slide for how to calculate Demand Response Value (DRV)
Use of Generation	May use a generator, however subject to federal and state laws / requirements

ERCOT

Rule Summary – ERS

Program Feature	Description
Program Period(s)	Oct 1 thru Jan 31 ; Feb 1 thru May 31 ; June 1 thru Sep 30
Eligibility	Minimum resource size of 0.1 MW (can be aggregated across sites), 15 min interval data meter, Ability to curtail with either 10 min OR 30 min advance notice.
Payment Basis	Based on the enrollment offer and price at which each time period is cleared. Based on the performance on test and availability of load during entire contract period
Aggregation	Competitive service area zones and NOIEs (Non Opt-in Entity Load Zones)
Enrollment	Procurement schedule published by ERCOT for every contract period. • ERIDs (typical deadline one month in advance of start of contract period). ERIDs - Info on customer sites and ESIDs. Cannot add or delete sites after the deadline. Contract signature must be in place prior to enrollment deadline • Offers(deadline 20 days in advance of contract period). Info on capacity (mw), baseline selection and price bids. MW Offers, baseline and prices locked out for entire contract period
Time Periods	TP1 (5am-8am); TP2(8am-1pm); TP3(1pm-4pm); TP4(4pm-8pm); TP5(8pm-10pm); TP6(10pm Friday thru 5am Mon including weekend)
Metering	15 min interval meter, revenue grade meter,
Testing Requirements	Performance tests: New resources tested within first two weeks of contract start date. If test is passed it is not retested for at least 330 days. If failed gets retested approx. within 2 weeks of test results published. Test results published 30-25 days after the test conducted. Availability: If resource fails availability for a given contract period, it gets retested again after availability results are published (typically 30-45 days after end of contract period)
Event Dispatch	10 min for ERS 10 ; 30 min for ERS 30 Dispatched only in the time periods that resource is enrolled. Minimum 45 min and maximum 8 hours.
Performance	Measured based on test/event performance and availability. Event performance factor <0.95 results in payment reduction. Resource availability factor < 0.85 results in payment reduction
Payment	Payments processed after the end of the contract period after both test/event performance and availability results are available
Use of Generation	• It needs to meet the federal RICE NESHAP criteria • so cannot be an emergency generator. needs to have permission to run generator in non-emergency situations and DR • as well as meet EPA's criteria and Texas Commission on Environmental Quality's emission rules/regulations

MISO

Rule Summary – LMR

Program Feature	Description
Program Period(s)	**June 1 – May 31** (Summer: June-September, Winter: October-May)
Eligibility	> 100 kW - any MISO Zone behind participating local balancing authority (LBA).
Payment Basis	Capacity payment (prices determined in annual Resource Planning Auction (RPA)) – zonal capacity rate * enrolled capacity Energy payment (events only) – RT LMP * hourly reduction
Aggregation	Primarily dispatched by zone – can aggregate smaller loads by LBA
Enrollment	**2/1** Deadline for existing LMR **3/1** Deadline for new LMR
Market Offers (if applicable)	Currently, no energy market offer requirement .
Metering	1-hour interval metering required
Testing Requirements	Various options available
Event Dispatch	1 to 12 hour Notification (may specify in enrollment), available 24X7 Must be able to maintain reduction for up to 4 hours Must be able to respond to first 5 events in a given Summer Season
Performance	Measured against CBL – average hourly intervals for last 10 non-event business days (or last 4 weekend days if applicable) prior to event dispatch. May select adjustment options or propose a customer baseline (subject to MISO approval) at time of enrollment. Hourly meter data must be submitted within 53 days of dispatch. Payments prorated for underperformance , plus LMR subject to pay “cost to replace” unforced capacity (unless outage scheduled or force majeure circumstances)
Payment	Capacity payments made monthly Capacity payment begins in June, adjusted based on actual performance accordingly
Use of Generation	Customer is responsible for its compliance with all federal, state and local requirements for utilizing generators for DR programs