Load Management and PRD Event Performance Education

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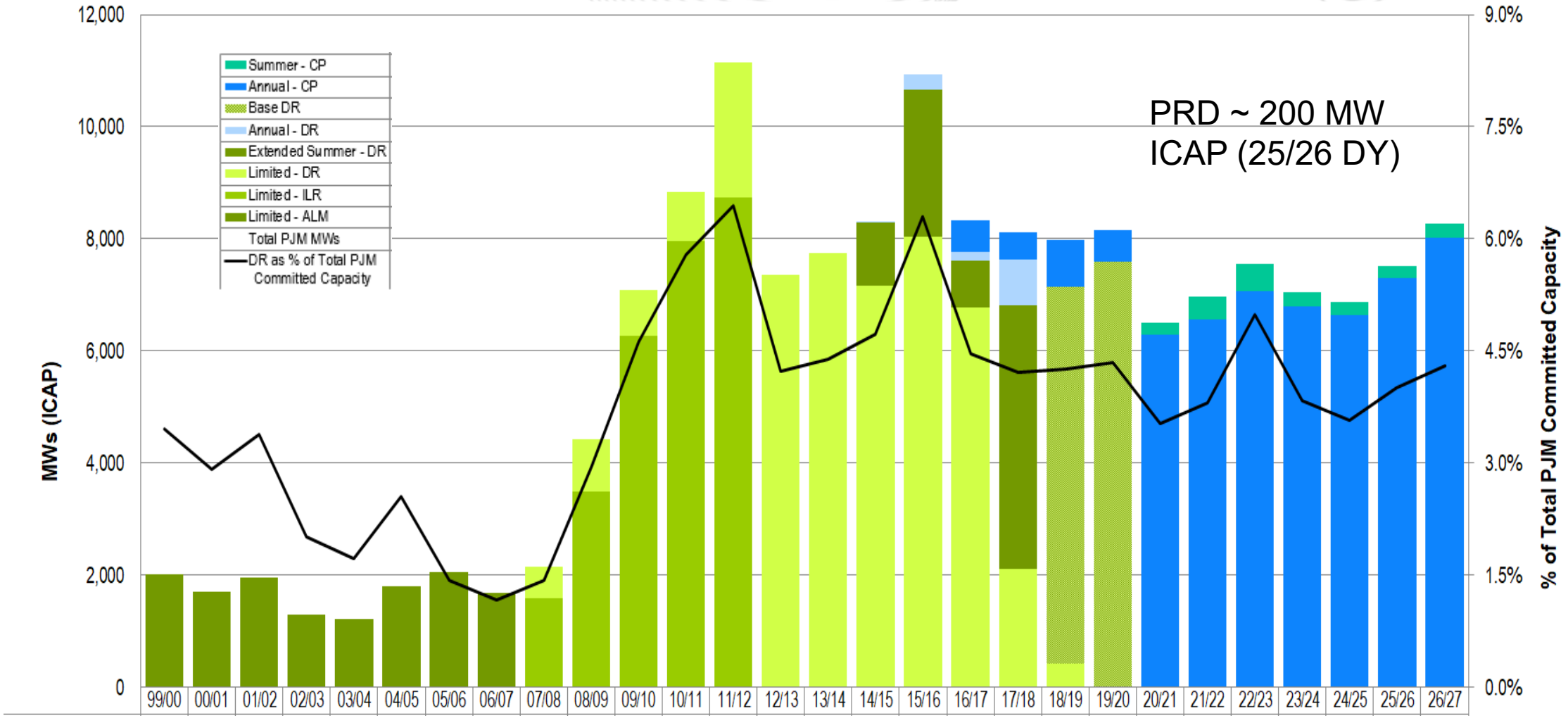
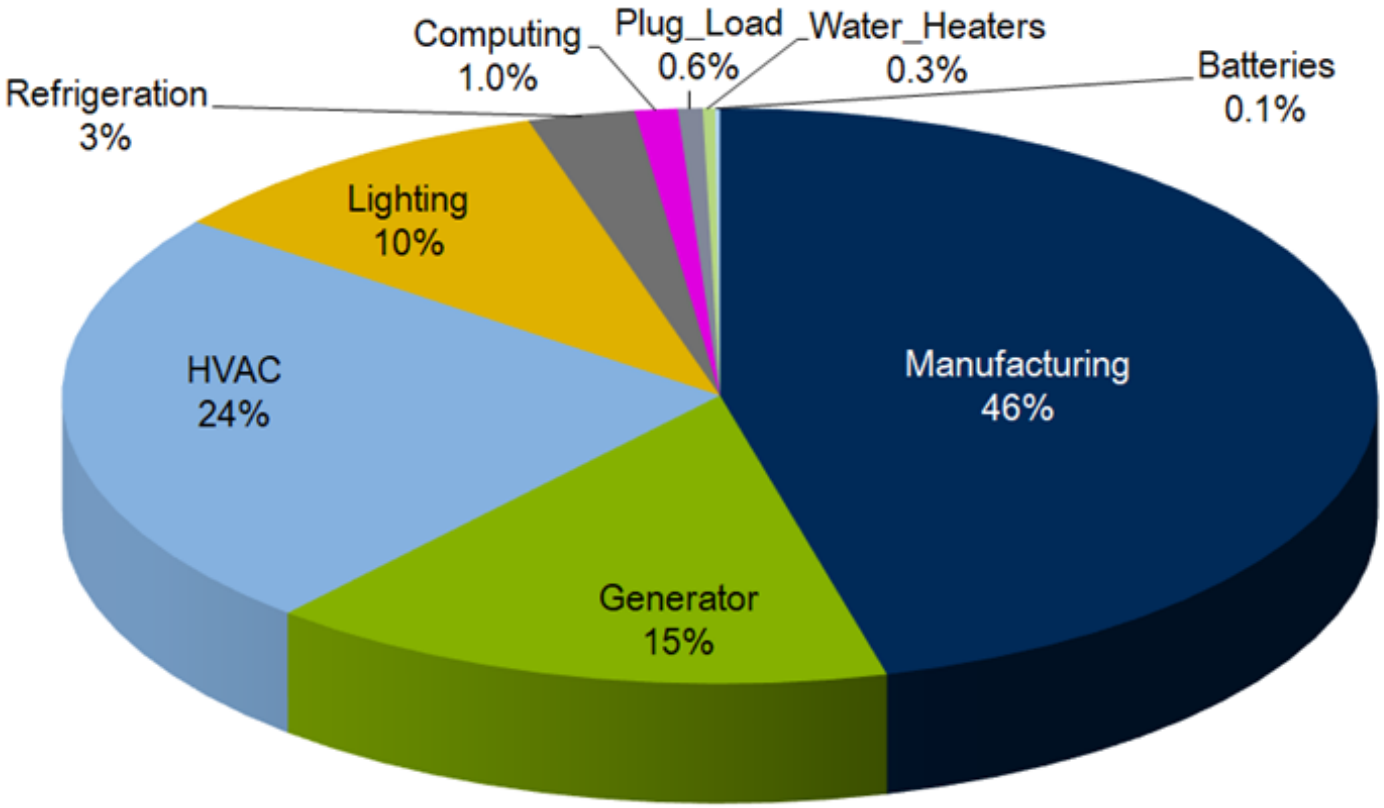
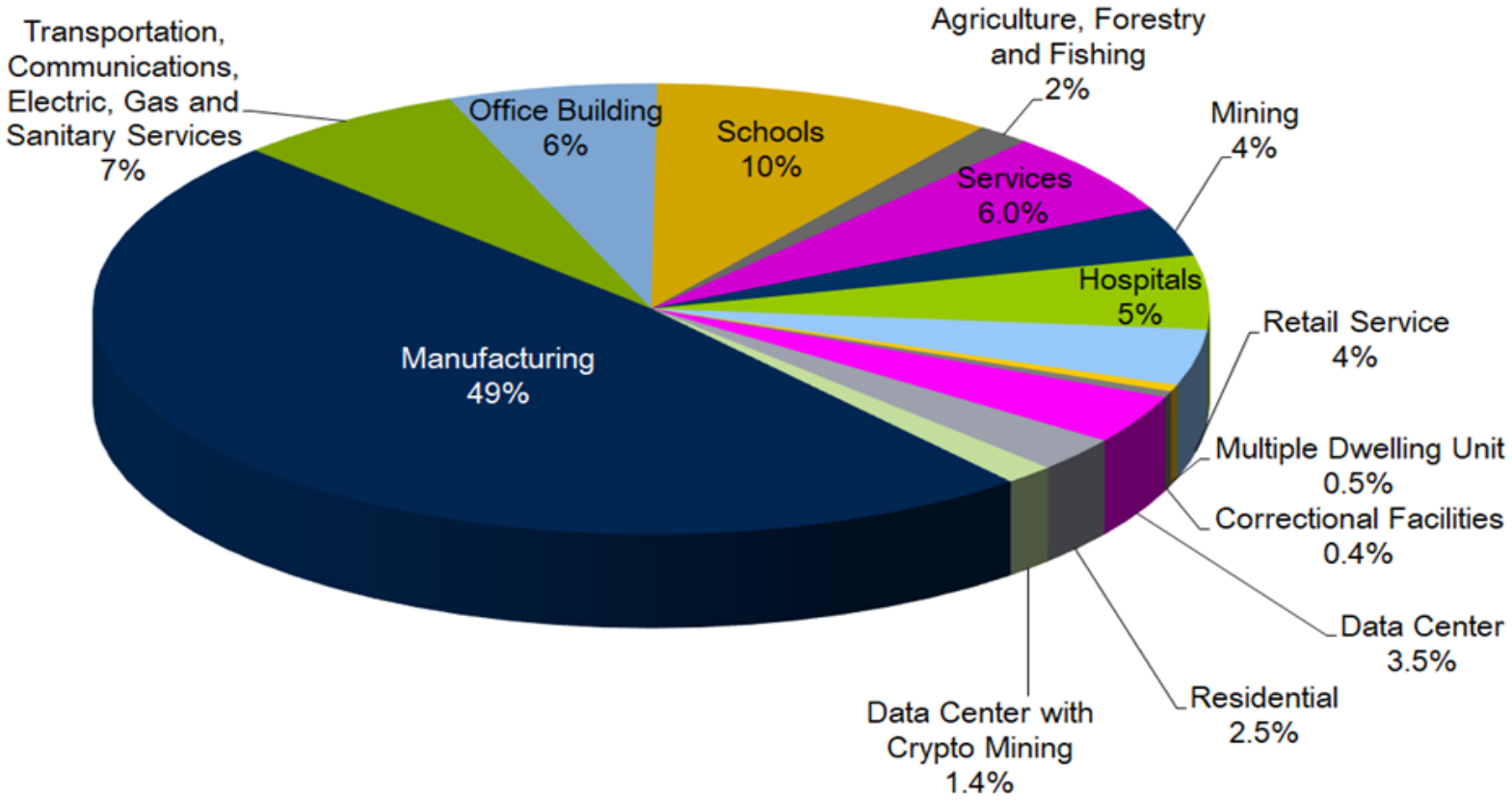
DR evolution and capacity commitments over time



How is load reduced to meet the capacity commitments?

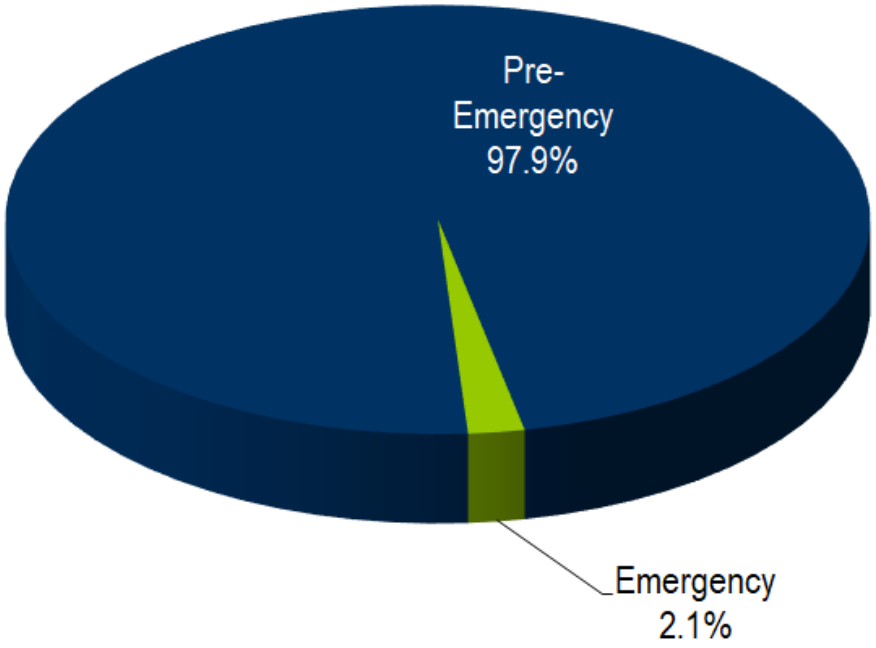


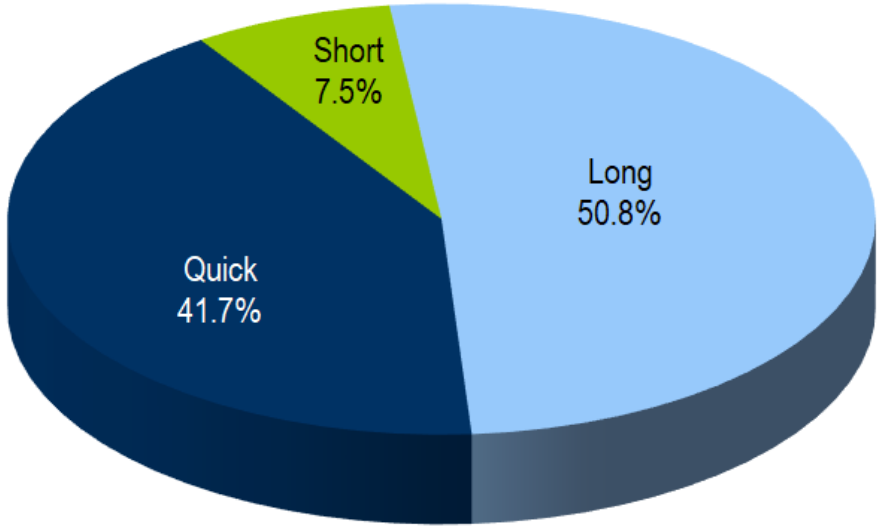
Business segments that provide capacity



Majority of DR is provided by Curtailment Service Provider that is not the EDC or LSE

Load Management Nominated ICAP MW breakdown





Quick = 30 min lead (default), Short = 60 min lead, Long = 120 min lead

Load Management (Capacity and Energy) requirements

- Offer in auction(s) similar to all other capacity resources
- Load Management = Emergency DR + Pre-Emergency DR
  - Emergency DR = behind the meter generator with permit that requires an EEA-2 to be issued in order to operate
    - EEA-2 as when a grid operator is no longer able to provide its expected energy requirements, but is still able to maintain minimum contingency reserve requirements.
  - Pre-Emergency DR = everything except Emergency DR
- Availability (through 26/27 DY)
  - Through 26/27 DY
    - June through Oct and following May: 10am to 10pm
    - Nov through April: 6am to 9pm
  - 27/28 DY and future
    - All hours (8760)

Registrations

- Capacity accreditation/Nominated Capacity
  - Summer ICAP: Peak Load Contribution (“PLC”) – (summer firm service level (“FSL”) * line loss factor)
  - Winter ICAP: (Winter Peak Load (“WPL”) * Winter Weather Adjustment Factor (WWAF) – winter FSL) * line loss factor
  - UCAP = ICAP * ELCC factor
- Hourly metering by location
  - +/- 2% accuracy

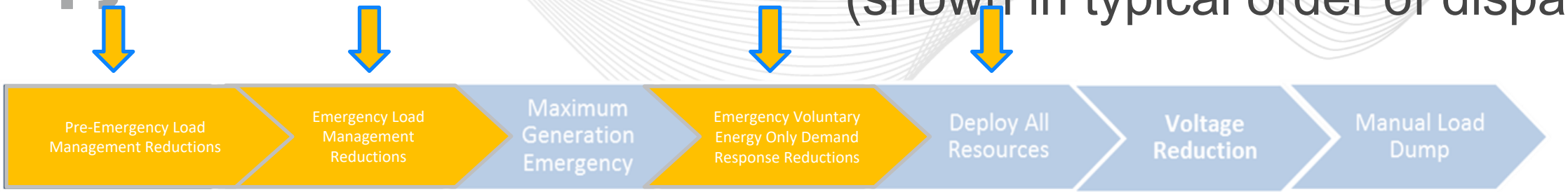
Customer specific PLC is also used to determine daily LSE capacity obligation which determine the LSE capacity charges

Expected Load Reduction Reporting

- CSP's are required to report accurate expected real time energy load reductions by:
  - Pre Emergency vs Emergency
  - Lead time
  - Product
  - Zone
- Expected real time energy load reductions represent amount of energy that CSP expects will be reduced. This is typically based on the difference between the CBL and expected load
  - If location load is already low and will not be reduced further – CSP should include 0

PJM will use expected load reductions to determine amount of DR to dispatch

Capacity Shortages – Actions (shown in typical order of dispatch)



Pre-Emergency Load Management Reductions: used to avoid reserve shortages (honor lead times)

Emergency Load Management Reductions: Used when PJM expects to be short on reserves (honor lead times)

Emergency Vol. Energy Only DR: Dispatch of customers registered under this program (not LM) for voluntary load relief

Event Notification Elements

Criteria	Load Management Event
Type	Pre-Emergency, Emergency
Lead Time	30, 60, 120 min
Product	CP
Location	Zone, Subzone
Start Time	Time reductions must begin
End Time	Time event is complete

Subzonal event will be subset of registrations for above elements based on smaller geographic area than a transmission zone

Load Management events

- Required to respond when dispatched and subject to PAI (if triggered)
- Energy load reductions receive compensation based on offer price. Offer price caps based on
  - 2 hour lead: $1,100 mwh
  - 1 hour lead: $1,000 + 50%* Reserve Penalty Factor (or $1,425 mwh)
  - 30 minute lead: $1,000 + Reserve Penalty Factor - $1 (or $1,849 mwh)
- Energy load reduction based on Customer baseline (“CBL”) – load
  - CBL is a “customer specific” forecast for real time hourly load

Load Management Compliance and Penalties

Daily Deficiency Penalty

- Daily Deficiency penalty applied when sum of nominated UCAP on registrations is less than linked Capacity Exchange capacity resource UCAP commitment
  - CP DR Minimum of Sum of Summer Nominated UCAP and Sum of Winter Nominated UCAP for all registrations associated with resource
  - Summer DR is any excess summer capability above the CP/annual DR capability
- Daily Deficiency Rate applied will be commitment-specific
- Daily Deficiency Rate for Shortfalls due to CP commitments is based on party's Weighted Average RCP for CP commitments for such resource
- Daily Deficiency Rate = party's commitment-specific WARCP for such resource plus higher of [0.2 * commitment–specific WARCP for such resource OR $20/MW-day]

It is critical that CSP links registrations to appropriate Capacity Exchange resource to avoid unnecessary penalty

Example of commitment-specific Daily Deficiency Rate and Daily Deficiency penalty charge

CP Capacity Resource clears MWs in BRA & 2nd IA

	BRA MWs Cleared (UCAP MWs)	BRA RCP ($/MW-day)	2nd IA MWs Cleared (UCAP MWs)	2nd IA RCP ($/MW-day)	Total Commitments (UCAP MWs)	WARCP ($/MW-day)	DDR ($/MW-day)
CP	100	$200	5	$220	105	$200.95	$ 241.14

CP WARCP = [(100 MW *$200/MW-day)+(5 MW *$220/MW-day)]/105 MW = $200.95/MW-day

[*0.2 * commitment–specific WARCP for such resource* OR $*20/MW-day*] Higher of → $40.19 / $20.00

CP DDR = $200.95/MW-day + ($40.19/MW-day) = $241.14/MW-day

Penalty Calculation = CP DDR * Commitment Deficiency[1] in UCAP (MWs)

= $241.13 * 105[1] = $25,319.70/day

Load Management event compliance

- Resource are required to respond to all events.
- If a PAI is triggered, then Resources with CP commitments that fail to perform are subject to Non-Performance Charge and resources (capacity or energy-only) that over-perform may be eligible for a Bonus Performance Credit
- Expected performance – actual performance
  - Expected performance based on ICAP commitment for registration(s) dispatched
    - Commitment prorated to registrations based on registration nominated amount
  - Actual performance based on PLC or WPL compared to actual metered load
- Load reductions (performance) is aggregated across the emergency action area.
- Capacity load reduction are also used as addback to develop unrestricted load forecast
  - Also used by EDC for subsequent year's PLC (avoid double counting between wholesale revenue and retail capacity cost avoidance)

Load Management Tests and Retests

Summary of Testing Requirements

- Tests are designed to be similar to actual Load Management (LM) events
  - If registrations are dispatched during a PAI event then no test is required
- Tests will be two hours in duration and scheduled by PJM throughout the year, including winter months
- Zone performance >75% can schedule their own retest(s) to improve performance. Others will have the opportunity to request a one-time retest scheduled by PJM
- The CSP will receive energy compensation for the load reductions during the test based on real time LMP
- The penalty for failure to perform is based generally on MW shortfall quantity and Provider's Weighted Daily Revenue Rate plus higher of $20 or 20% adder (detailed in M18 Section 9.1.6)

Example Test Cycle

I also know there will be no tests in any other zones. Get maintenance done there

I know test can only take place on 10 potential days

PJM notifies CSP of zones to be tested

PJM notifies CSP by 10am that test will be tomorrow

I know test is tomorrow and I have at least 13 hours to prepare

Check that my generator can start

July

		7/1/2019	7/2/2019	7/3/2019	7/4/2019	7/5/2019	7/6/2019	7/7/2019	7/8/2019	7/9/2019	7/10/2019	7/11/2019	7/12/2019	7/13/2019	7/14/2019	7/15/2019	7/16/2019	7/17/2019	7/18/2019	7/19/2019	7/20/2019	7/21/2019	7/22/2019	7/23/2019	7/24/2019	7/25/2019	7/26/2019	7/27/2019	7/28/2019	7/29/2019	7/30/2019	7/31/2019
Potential Test Days																X	X	X	X	X			X	X	X	X	X					
Actual Test Day																		X														

PJM notifies CSP with normal lead time

I know test will occur only between 11a-6p and I will be given my lead time

Each zone tested one day per year for 2 hours.

PAI event (Registrations dispatched by PJM)

PAI penalty

(~$2,300 MWh, RTO, 27/28)

+ PAI Bonus

+ Energy $ (strike price)

+Potential energy cost reduction (depends on retail rate)

+ No Test penalties

Conservative estimated incentive

$3,725 MWh = $2,300 (avoided penalty) + $1,425 (short lead strike price)

Non-PAI event (Registrations dispatched by PJM)

+ Energy $ (strike price)

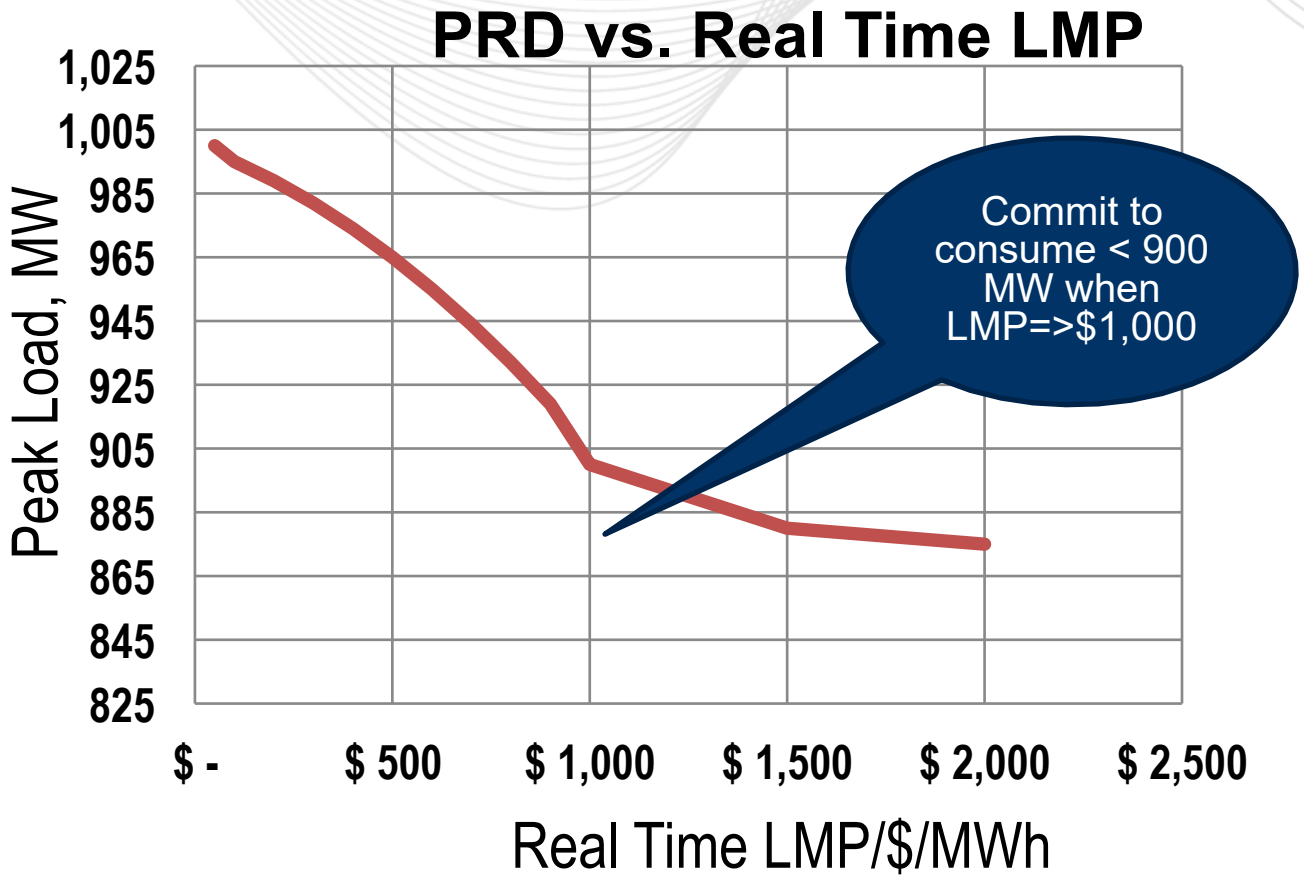
+ Potential energy cost reduction (depends on retail rate)

+Option to substitute event performance for test performance

Conservative estimated incentive
$1,425 MWh (short lead strike price)

- PRD

Price Responsive Demand (“PRD”)



Price Responsive Demand (PRD) – load that will automatically respond to energy prices and be off the grid during PJM emergency in exchange for a reduction in the capacity requirement.

Key PRD rules

- Dynamic retail rates
- Supervisory Control (remote control to reduce load)
- Registrations by EDC account number by pnode
- Capacity Revenue based on Final Zonal Clearing Price (not BRA clearing price)
  - No energy revenue
- Submission of PRD curves
- Penalties (commitment, PAI and test)
- PRD commitments can only be replaced by other PRD commitments

Key PRD processes when there is a PRD commitment

PRD Registration

- Identify each customer location (EDC account #) by Transmission Zone, EDC, and Pnode
  - Location may not be registered as Economic Load Response, Emergency Load Response, Peak Shaving Adjustment, or PRD Plan of any other provider
  - PRD does not receive energy revenue
- Determine the nominated capacity ICAP based on the EDC determined peak load contribution (PLC)
  - Nominated ICAP Capacity = PLC – (Firm Service Level* Line Losses)
  - UCAP MW = ICAP MW * FPR
- Ensure hourly metering is +/- 2 percent accuracy

PRD Curves

- PRD provider will manage PRD curves & reduce load based on such curve
  - Load (MW) by Price by day by hour by pnode
  - PJM will measure compliance and assess penalties when LMP=>PRD price and there is a Performance Assessment Interval
- PJM will use PRD curve in overall dispatch to maintain power balance
  - When PRD is expected to reduce load PJM will commit other resources based on a lower load forecast

PRD Test

- PRD that is not required to reduce load for a PAI is required to perform a test
- Test requirements:
  - PJM initiated 2 hour test per year
  - Test may occur throughout the year
  - Ability for retest

PRD Penalties

Commitment Penalty (do not have enough customers to cover commitment)

Performance Compliance Event Penalty (don't reduce enough load when required)

Test Penalty (don't reduce enough load when required)

Penalty calculations

- Commitment Penalty =Shortfall (MW) * Forecast Pool Requirement * [Weighted Final Zonal Capacity Price in $/MW-Day + Higher of (0.2 * Weighted Final Zonal Capacity Price) or $20/MW-day
  - Shortfall (MW) = Amount Committed for a zone in PRD Plan – Nominated ICAP of registrations in the zone
- PAI = MW shortfall * [Forecast Pool Requirement] * [Weighted Final Zonal Capacity Price in $/MW-Day + Higher of (0.2 * Final Zonal Capacity Price) or $20/MW-day] * 365 days
  - Only assessed if LMP>Strike price for more than 3 intervals AND PJM declares a PAI is each interval
- Test Penalty – same as Commitment Penalty

PRD PAI event
(RT LMP > strike price AND PJM PAI event in >3 intervals)

+ PAI Bonus

+ Potential energy cost reduction (depends on retail rate)

PAI penalty

(~$2,300 MWh, RTO, 27/28)

Conservative estimated incentive
$3,725 MWh = $2,300 (avoided penalty) + $1,425 (energy cost savings)

PRD Non-PAI event (RT LMP > strike price)

+ Potential energy cost reduction (depends on retail rate)

Conservative estimated incentive
$1,425 (energy cost savings)

- Summer ’25 event performance

Historic Performance summary

	Load Management	
Delivery year	Event performance	Test performance
2012/13	104%	116%
2013/14	94%	129%
2014/15	No Events	144%
2015/16	No Events	134%
2016/17	No Events	153%
2017/18	No Events	163%
2018/19	No Events	146%
2019/20	78%	150%
2020/21	No Events	160%
2021/22	No Events	154%
2022/23	125%	410%
2023/24	No Events*	122%
2024/25	No Events*	103%

Load Management Deploy and Release Times (No PAI events)

– June 23, 2025
  - Mid-Atlantic/Dominion Zones

Notification Time	Deploy Time	Release Time	Resource Type	Lead Time	Zones
13:00	15:00	22:00	Pre-Emergency	Long_120	AECO, BGE, DOM, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
14:00	15:00	22:00	Pre-Emergency	Short_60	AECO, BGE, DOM, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG

– June 24, 2025
  - RTO wide

Notification Time	Deploy Time	Release Time	Resource Type	Lead Time	Zones
13:00	15:00	22:00	Pre-Emergency	Long_120	BGE, DOM, PECO, PEPCO
13:30	15:30	22:00	Pre-Emergency	Long_120	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
14:00	16:00	22:00	Pre-Emergency	Long_120	AEP, APS, DAY, DUQ
14:30	16:30	22:00	Pre-Emergency	Long_120	ATSI, COMED, DEOK, EKPC
14:00	15:00	22:00	Pre-Emergency	Short_60	BGE, DOM, PECO, PEPCO
14:30	15:30	22:00	Pre-Emergency	Short_60	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
15:00	16:00	22:00	Pre-Emergency	Short_60	AEP, APS, DAY, DUQ
15:30	16:30	22:00	Pre-Emergency	Short_60	ATSI, COMED, DEOK, EKPC

Load Management Deploy and Release Times (No PAI events)

– June 25, 2025
  - Mid-Atlantic/Dominion/APS Zones

.

Notification Time	Deploy Time	Release Time	Resource Type	Lead Time	Zones
13:00	15:00	17:45	Pre-Emergency	Long_120	APS
13:00	15:00	18:10	Pre-Emergency	Long_120	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
13:00	15:00	19:00	Pre-Emergency	Long_120	DOM
14:00	15:00	17:45	Pre-Emergency	Short_60	APS
14:00	15:00	18:10	Pre-Emergency	Short_60	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
14:00	15:00	19:00	Pre-Emergency	Short_60	DOM

Load Management Deploy and Release Times (No PAI events)

– July 28, 2025
  - BGE, DOM, PEPCO Zones

Notification Time	Deploy Time	Release Time	Resource Type	Lead Time	Zones
14:45	16:45	21:00	Pre-Emergency	Long_120	BGE, DOM, PEPCO
14:45	15:45	21:00	Pre-Emergency	Short_60	BGE, DOM, PEPCO

– July 29, 2025
  - RTO wide

Notification Time	Deploy Time	Release Time	Resource Type	Lead Time	Zones
13:00	15:00	20:45	Pre-Emergency	Long_120	ATSI, BGE, DOM, PEPCO
13:30	15:30	21:15	Pre-Emergency	Long_120	AEP, EKPC
14:00	16:00	21:30	Pre-Emergency	Long_120	AECO, DPL, JCPL, METED, PECO, PENELEC, PPL, PSEG
16:00	18:00	21:45	Pre-Emergency	Long_120	APS, COMED, DAY, DEOK, DUQ
13:00	14:00	20:45	Pre-Emergency	Short_60	ATSI, BGE, DOM, PEPCO
13:30	14:30	21:15	Pre-Emergency	Short_60	AEP, EKPC
14:00	15:00	21:30	Pre-Emergency	Short_60	AECO, DPL, JCPL, METED, PECO, PENELEC, PPL, PSEG
16:00	17:00	21:45	Pre-Emergency	Short_60	APS, COMED, DAY, DEOK, DUQ

Load Management Deploy and Release Times (No PAI events)

– August 11, 2025
  - BGE Zone

Notification Time	Deploy Time	Release Time	Resource Type	Lead Time	Zones
8:45	10:45	20:00	Pre-Emergency	Long_120	BGE
9:00	10:00	20:00	Pre-Emergency	Short_60	BGE
9:30	10:00	20:00	Pre-Emergency	Quick_30	BGE
14:15	15:15	17:15	Emergency	Short_60	BGE
14:15	14:45	17:15	Emergency	Quick_30	BGE

Operations

- Overall communication between PJM and CSP went well
  - DR polling
  - Emergency Procedure messages
  - All Call
- CSP reported expected energy reduction were higher than realized energy reductions
- Energy Settlements (DR Hub CBL calculation was slow but has been updated)
  - June events – September bill ($36.5 million)
  - July events – November bill (tbd)
  - August event – November bill (tbd)

June, July and August ’25 Load Mgt Event Performance
DR Performance is based on committed ICAP

	6/23/2025	6/24/2025	6/25/2025	7/28/2025	7/29/2025	8/11/2025	Overall
Estimated average hours	7	7	4	5	6	10	
Total Capacity Commitment (MW ICAP)	1,387	4,053	1,687	571	4,038	226	11,962
Total Capacity Load Reductions (MW ICAP	876	2,936	1,041	386	2,607	120	7,966
Total Performance	**63%**	**72%**	**62%**	**68%**	**65%**	**53%**	**67%**
Total Shortfall	511	1,117	646	185	1,431	105	3,996
CSP Capacity Commitment (MW ICAP)	1,307	3,504	1,607	491	3,490	226	10,623
CSP Capacity Load Reductions (MW ICAP)	825	2,241	962	322	1,990	120	6,460
CSP Performance	63%	64%	60%	66%	57%	53%	61%
CSP Shortfall	482	1,263	644	169	1,500	105	4,163
EDC Capacity Commitment (MW ICAP)	*	549	*	*	549		1,339
EDC Capacity Load Reductions (MW ICAP)	*	699	*	*	613		1,506
EDC Performance		127%			112%		112%
EDC Shortfall		(150)			(64)		(167)

Notes:
1) DR ELCC for 25/26 = 77%
2) Capacity commitment has not been reduced for daily deficiency penalties although penalty only applied to one penalty
3) Capacity load reduction based on sum of average reduction per registration
4) * indicates insufficient number of members to publish information.

Winter 25/26 readiness

- CSP is required to have customers reduce load when dispatched
  - Customer should not evaluate system conditions and determine if “economic” for them to reduce load
- CSP is required to provide accurate expected energy reduction to enable PJM to effectively manage the system during emergency conditions
  - Ensure estimate is based on correct type of day and hourly load conditions.
    - Estimate should NOT simply be nominated MW.
  - Communicate with customer to incorporate near real time feedback
- Emergency Procedure “Maximum Generation Emergency/Load Management Alert“ is typically posted the day before **and indicates the potential for dispatch the following day**
  - Provides advanced warning that Load Mgt will likely be dispatched

- If PJM operators knows Load Mgt needs to be dispatched, then operator will dispatch in advance of the lead time (if possible)
  - CSP should follow the dispatch signal, do not respond early
  - For example, long lead (2 hour) dispatched at 0300 with instructions that load must be completely down by 0800. The load should begin the reduction at 0600 if it will take 2 hours to be fully reduced. The load should not begin the load reduction at 0300.
    - If it will only take 1 hour to reduce the load (because it can do quicker on this day) then it should begin at 0700)
- PJM may dispatch twice in one day to manage morning and evening winter peaks

27/28 BRA interim process

- PJM intends to incorporate summer performance in the determination of “Existing” DR resources unless CSP can provide evidence they will perform in 27/28 DY
  - CSPs with overall performance below 85% should have DR Plan portion of Existing MWs dispatched adjusted down based on DR Resource specific summer ’25 event performance unless it can be demonstrated that customer will be able to deliver load reductions in the future
- CSP must provide its analysis that the load reduction will be physically deliverable in 27/28 or submit an updated DR Plan with Existing DR MWs derated.
- Examples of such analysis may include:
  - Change in CSP contract provision
  - Attestation from customers (registration/location) that did not perform with changes made that will facilitate the load reductions
  - Implementation of new controls and/or process to reduce load
  - Other

- Detailed DR reports are under the Reports section of https://www.pjm.com/markets-and-operations/demand-response
  For example:
  - 24/25 Annual Load Mgt Performance Rpt
  - Detailed monthly DR participation report
  - August 11, 2025 Hot Day Report

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