Demand response roadmap for the New Jersey Board of Public Utilities

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Background and motivations

- The New Jersey Board of Public Utilities (BPU) requested technical assistance from Berkeley Lab to inform their strategy for advancing a demand response (DR) portfolio in the Triennium 3 program cycle that:
  - Has programs implemented by third parties
  - Addresses both bulk power and distribution grid needs
  - Uses open communication protocols
  - Allows flexible customer participation

- Berkeley Lab reviewed BPU goals and the current the state of DR in New Jersey and used its Demand Flexibility Maturity Model to develop a roadmap that:
  - Characterizes components of BPU's vision of a demand response portfolio
  - Delineates milestones for the portfolio's development
  - Identifies utility investments and BPU actions that achieve those milestones

Demand flexibility roadmap timeline

	Lay the foundation for DR growth **Phase 1**	Establish programs **Phase 2**	Scaling up DR grid impacts **Phase 3**
Retail	Revise quantitative performance indicators and advance program design through T3 order	Utilities deploy DR infrastructure and new program capabilities	Programs scale up impacts
Wholesale	Establish systems and processes for wholesale market aggregations	DER aggregations in PJM start operations	Retail and wholesale DR operate in coordinated manner
NWAs	Identify distribution system constraints establish NWA framework	Utilities procure NWA solutions	Utilities implement NWA and assess performance

December 2025
BPU issues
Triennium 3 order

July 2027
Triennium 3
Year 1 starts

July 2028
Triennium 3
Year 2 starts

June 2030
Triennium 3
Year 3 ends

Phase 1: December 2025-June 2027

The BPU revises the quantitative performance indicators for T3 to promote DR growth

Phase 1: December 2025

- The BPU sets peak electricity demand reduction goals for demand response programs that increase over the T3 period
  - Targets are specific to each utility and are based on the economic potential for peak demand reductions in the 2025 potential study conducted by DNV
  - Utilities must provide a narrative that explains how they plan to achieve increasing goals and expand customer population that participates in the programs

- T3 filing requirements stipulate that peak demand reductions that contribute to the achievement of the peak demand reductions target be:
  - Coincident with PJM system peak demand
  - Verified through post-event measurement at the meter level

- The BPU increases the weight of annual peak demand reductions in the Quantitative Performance Indicators (QPIs)
  - The achievement of energy efficiency and demand response program peak demand targets are each a separate QPI
  - The demand response peak demand target has a larger weight than the efficiency peak demand target to encourage the growth of demand response

T3 order funds new avoided cost and potential studies to inform T4 planning

Phase 1: December 2025

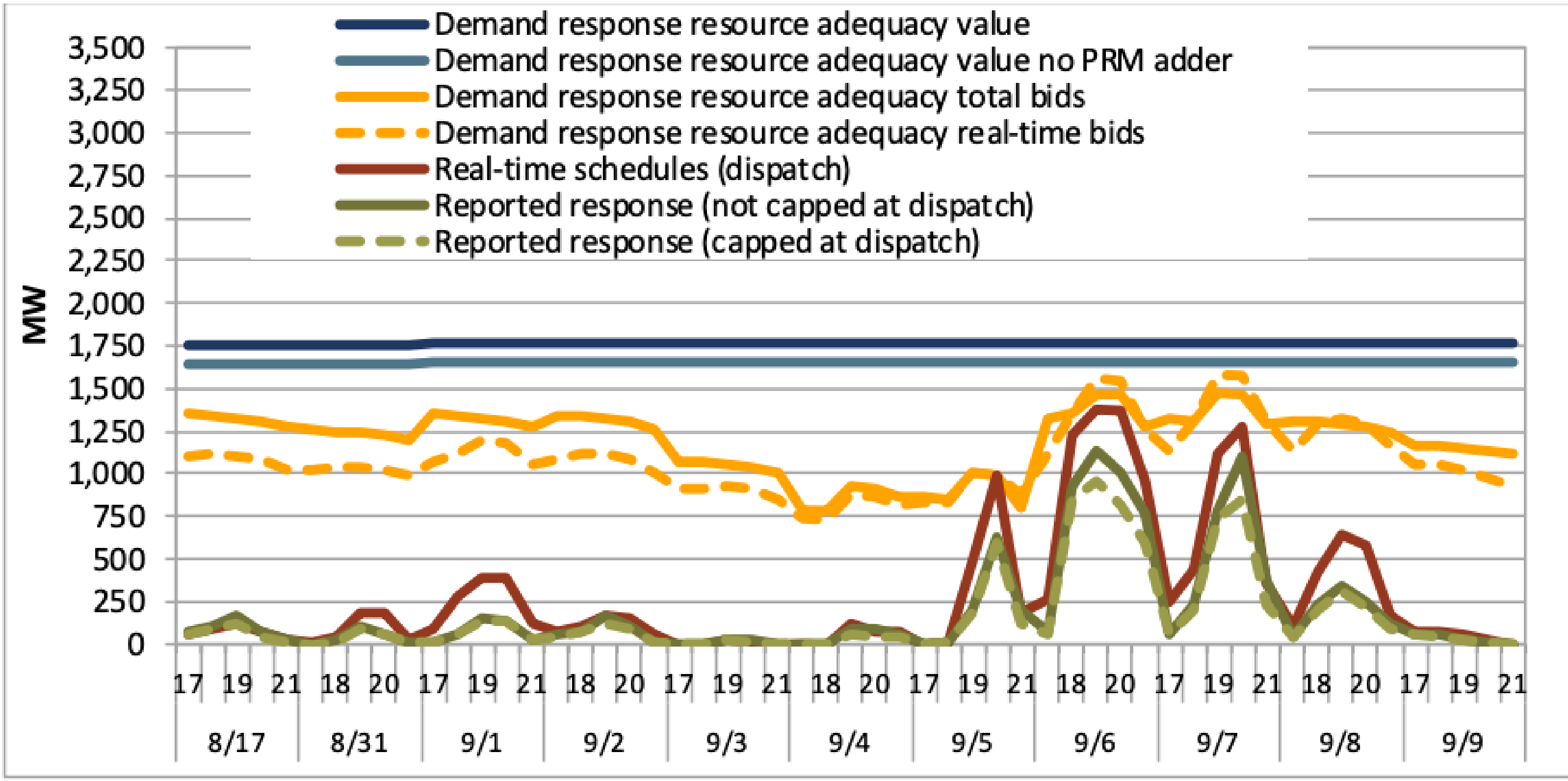
- The Triennium 3 order requires that the utilities co-fund an avoided cost study that:
  - Considers the long-term energy system impacts of energy and peak demand reductions
  - Includes avoided costs not considered in T2 (e.g. reliability)
  - Aligns methods for avoided costs with leading practices in other states
  - A statewide evaluator conducts at the direction of an EM&V working group that includes BPU staff, Rate Counsel, and the utilities

- The Triennium 3 order requires that statewide evaluator conduct a DR potential study that:
  - Considers a range of demand response strategies including but not limited to:
    - Wi-Fi smart thermostats
    - Managed electric vehicle charging
    - Dynamic electricity rates
    - Battery storage
    - Water heating (grid-connected and DLC)
  - Uses the results of the updated avoided cost study to estimate the economic potential of demand response
  - The BPU uses to inform T4 peak demand reduction goals
  - Incorporates data from the implementation of programs in T3 to inform study assumptions

T3 order requires that utilities implement DR programs through third parties
Phase 1: December 2025

- The BPU supports the development of a third-party DR ecosystem by requiring that each retail program:
  - Allows customers to participate through one of multiple third-party device makers and or DER aggregators
  - Utilizes performance-based contracts and partnerships in which utilities:
    - Aggregate demand reductions in events affects payments to third parties
    - Validate of third-party DF commitments (capacity) using load data
    - Make ongoing performance-based adjustments to third-party DF commitments as events are called, including test events
  - Allows enrolled DERs to be part of aggregations that participate in PJM wholesale markets, including through aggregators that are not the program implementer
  - Enables customer choice to enrollment, unenrollment, changes in aggregator, registered devices, and dispatch options
  - Prioritizes open standards (e.g. OpenADR) and ensure interoperability of customer devices across program implementers
  - Prevents conflicting dispatches with other programs
  - Tracks and validates data on program enrollment (e.g. enrollment date by customer ID) and operations (e.g. customer IDs that received dispatch for a given event)

Example report of hourly DR load impacts (reported response) relative to resource adequacy value



Source: CAISO (Peak period hourly DR load impacts during summer 2022 heatwave)

T3 reporting requirements support DR program performance
Phase 1: December 2025

- The BPU establishes reporting requirements for utility DR programs, including:
  - Narrative descriptions in T3 plan of how programs will scale to meet increasing demand reduction goals
  - Annual reports in which that utilities document program performance and strategies to correct performance issues
  - Post-event EM&V reports that document event load impacts and performance issues
  - Data quality monitoring reports that assess data quality and availability

T3 order sets a regulatory schedule for plan development and approval

Phase 1: December 2025

- Utilities file T3 plans by May 31st 2026
  - Utilities have **seven months** to develop implementation strategy to meet new peak demand reduction goals and filing requirements

- The BPU approves the T3 plans by December 31st 2026
  - BPU has **seven months** to review filings, assess their compliance with filing requirements, and request revisions

- Utilities prepare for T3 implementation between January 1st 2027 and July 1st 2027
  - Utilities use the **six months** between plan approval and implementation to finalize contracts with third parties

T3 order sets schedule for avoided cost and potential studies

Phase 1: December 2025-July 2027

- Evaluator reviews leading practices in other states and identifies opportunities for advancing the methodology for estimating avoided costs and non-energy impacts in the New Jersey Cost Test and submits recommendations to the EM&V Working Group by December 31st 2026

- The EM&V working group submits recommendations on changes to avoided cost methods and categories to the BPU by March 31st 2027. The BPU issues an order on these recommendations by June 30th 2027.

- The statewide evaluator updates avoided cost and non-energy impacts methods and estimates between January 2027 and December 2027

- The statewide evaluator updates the demand response potential study using the latest avoided costs (January 2028 – June 2028)

BPU issues order on grid needs assessment to support grid services in the distribution system

Phase 1: March 2026

- The BPU issues an order that requires utilities to provide a 10-year feeder-level grid needs assessment report by June 2027
- The order defines the objectives of the grid needs assessment and requires that utilities report:
  - The types of grid needs they consider (e.g. thermal, reliability, voltage) and criteria for determining each type of grid need exists
  - The methods, tools, and data they use to identify grid needs
  - Load and peak demand forecasts used in the grid needs assessment as well as assumptions on customer growth, weather, and technology adoption made in the forecasting process
  - The magnitude, timing, and duration of each grid need and the conditions in which grid need occurs (i.e. normal or contingency conditions)
    - Tabular data, organized by feeder and year
  - Cost estimates for traditional solutions to each grid need
  - The process for prioritizing and selecting grid needs for investments over the 10-year period

The BPU creates process to prepare utilities for DER aggregations in PJM wholesale markets (1)

Phase 1: June 2026

- The BPU issues an order clarifies whether utilities can or cannot be aggregators

- The BPU requests that utilities submit proposals by December 2026 on investments needed to support their roles in:
  - Registering DERs by automatically reviewing customer location and whether DER is already part of another aggregation
  - Assessing safety and reliability risks of DER aggregations
  - Sharing data with PJM and aggregators
  - Customer information/billing system updates
  - Coordinating dispatches from PJM and retail programs

- The BPU requests that proposals include plans for a DER Registry that:
  - Centralizes data on DERs in retail programs and wholesale market aggregations
  - Manages validated data on DER attributes, operational characteristics, and performance
  - Supports program managers, enrollment validation processes, and external reporting needs with limited manual effort
  - Tracks all interconnected solar and batteries and DERs in retail programs
  - Tracks all wholesale market aggregations

The BPU creates process to prepare utilities for DER aggregations in PJM wholesale markets (2)

Phase 1: June 2026

- The BPU requests that proposals include plans for a DER Orchestration system that uses open standards (e.g. OpenADR and IEEE 2030.5) to coordinate dispatches across demand response programs and wholesale aggregations and automates:
  - Onboarding program devices and aggregations through an automated, user-friendly process with minimal administrative burden for EDCs, participants, and third-parties
  - Adjustments to participant enrollment, including changes in aggregator, registered devices, and dispatch options
  - Validating DF commitments using results from dispatches

- The BPU requests that by June 2027 utilities propose frameworks for:
  - Assessing the safety and reliability risks of DER aggregations, including the:
    - Types of risks considered
    - Methods, criteria, and metrics used to characterize those risks
  - Managing double compensation and conflicting dispatches, including:
    - The types of conflicts that may occur
    - Criteria for deciding which dispatch a DER should prioritize
  - Overriding dispatches from PJM to avoid distribution system issues, including:
    - The identification of situations in which overrides could occur
    - Criteria, metrics, and methods used to make override decisions

Example DER Registry data

Category	Required Data
Enrollment	Aggregator (if applicable)
	Type of DER
	Device manufacturer
	Serial ID
	Account ID
	Meter ID
	Rate schedule
	Enrollment start and end dates
	Enrollment state and end dates for other programs/aggregators
	Energy capacity (kWh) - How much energy does it carry?
	Demand capability (kW) - How fast can it charge and discharge?
Dispatch group	Bulk power system node
	Feeder ID (for distribution services)
	Program subgroup
Operational	Device runtime or state of charge
	For EVs - where the vehicle is located and charging
	Dispatch date
	Dispatch start and end time
	Expected performance
	Aggregator market bid prices and amounts (if applicable)

BPU issues a framework that guides NWA procurement process

Phase 1: June 2027

- Utilities file their grid needs assessments with the BPU
- The BPU issues an NWA framework that:
  - Describes objectives for NWAs
  - Identifies criteria for determining which grid needs are suitable for NWAs
  - Describes the technical and cost-effectiveness screens that determine whether to pursue suitable NWAs
  - Delineates the procurement process, including the eligibility of utility programs and rates
  - Determines whether energy and demand savings from the NWA contribute to Triennium goals
  - Describes scenarios for which utilities must develop contingency plans for NWA
  - Defines elements of performance evaluation process
- BPU orders utilities to identify NWA opportunities following the framework and to procure at least one solution, if it exists, by the end of Phase 2 (July 2028)

Phase 2: July 2027-June 2028

Utilities roll out DER Registry and Orchestration platform

Phase 2: July 2027-June 2028

- BPU approves proposals for utility investments that support PJM DER aggregations

- Each utility rolls out a DER registry and populates it with validated data on:
  - Battery storage and distributed solar systems that have interconnected in prior years and DERs enrolled in utility programs in prior years by December 31st 2027
  - New battery storage and distributed solar systems as they are interconnected
  - DERs in utility programs as they enroll
  - DER aggregations participating in PJM wholesale markets starting in February 2028

- Utilities rollout DER a Orchestration platform that:
  - Onboards retail program devices enrolled in prior years
  - Onboards retail program devices as they enroll in new programs
  - Validates peak demand reductions
  - Integrates program operations

- DER Registry supports DER aggregations in PJM wholesale markets by preventing double registration (same DER in multiple aggregations) and tracks the participation status of DERs in utility programs and aggregations

Regular reporting during the program year supports program performance

Phase 2: July 2027-June 2028

- Utilities provide post-event reports on program performance that:
  - Provide 15-minute demand impacts during event window and in hours preceding and following events
  - Use validated AMI data and EM&V practices
  - Leverage device-level data when available
  - Compare demand reductions to event capacity committed by third parties
  - Compare the number of customers who participated relative to those dispatched and enrolled
  - Identify performance issues and potential corrective actions
  - Are available to BPU and grid operators
- Utilities provide data quality monitoring reports to third party program implementers, customers, and third-party providers (weekly or more frequently)

Third party programs support achievement of demand reduction goals

Phase 2: July 2027-June 2028

- Third parties enroll customers into programs and target system-wide peak demand reductions and have:
  - Pre-event notifications to customers
  - Defined event windows for weekdays and weekends that align with bulk power system needs
  - Overrides to opt-outs during grid emergencies
  - Incentives that promote technology adoption, retain enrolled customers, and incentivize demand reductions during events
  - Test events that evaluate how resources respond under a variety of weather and system conditions

- Utilities validate third-party performance against commitments, enforce penalties, and terminate agreements for consistent underperformance

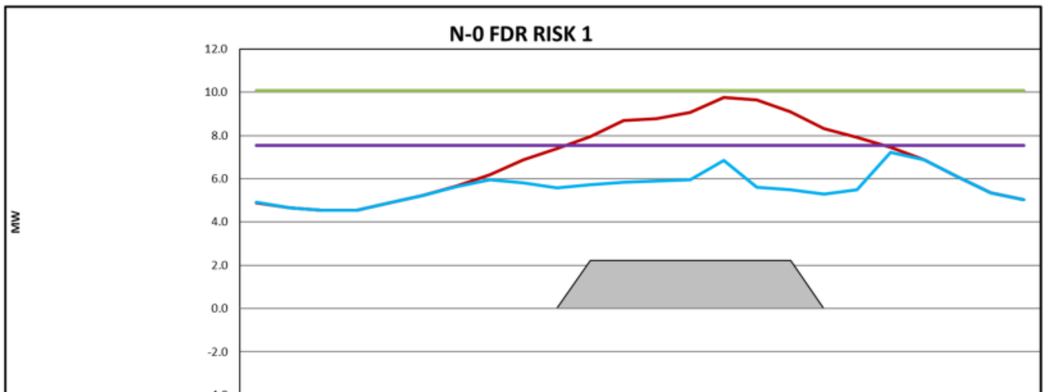
- Utilities achieve demand reductions goals for first year of T3

Utilities identify grid needs and procure NWA solutions

Phase 2: July 2027-June 2028

- Utilities identify which grid needs are suitable for an NWA and perform technical and cost-effectiveness screens (July 2027-Dec 2027)
  - Utilities report results of screening process to BPU

- Utilities procure NWA solutions through competitive process defined in framework (Jan 2028-June 2028)



	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Need Shape (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder Limit (MW)	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Feeder Load (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.7	6.2	6.9	7.4	8.0	8.7	8.8	9.1	9.8	9.7	9.1	8.3	7.9	7.5	6.9	6.1	5.3	5.0
Forecast Uncertainty Margin (MW)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Feeder Load With NWA (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.6	5.9	5.8	5.6	5.7	5.8	5.9	5.9	6.9	5.6	5.5	5.3	5.5	7.2	6.9	6.1	5.3	5.0
Solar Generation (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-1.1	-1.8	-2.2	-2.9	-2.9	-3.1	-2.9	-2.6	-2.1	-1.5	-0.9	-0.2	0.0	0.0	0.0	0.0
Battery State of Charge (MWh)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Xcel Energy Minnesota NWA technical screen from [2023 Integrated Grid Plan]

Frameworks and investments that support DER aggregations in PJM wholesale markets are final

Phase 2: February 2028

- BPU has approved frameworks for:
  - Reviewing safety and reliability of DER aggregations
  - Double compensation and conflicting dispatches
  - Utility overrides of PJM dispatches

- Utilities have completed investments that support FERC Order 2222 implementation, including the DER Registry and DER Orchestration System

- Utilities have systems that can:
  - Automatically determine DER eligibility and review incremental safety and reliability impacts of DERs in aggregation during registration process
  - Share data with aggregators and PJM
  - Override dispatches from PJM to prevent safety/reliability issues

- PJM wholesale markets open up to DER aggregations and utilities start receiving registration requests

Capabilities at the end of Phase 2

Phase 2: July 2027-June 2028

- A growing third-party DR ecosystem can integrate a wide range of DER aggregators and devices, particularly those with the largest market potential based on DER adoption data and near-term forecasts

- DER Orchestration platform and DER Registry have accurate and granular data and enable DR that addresses grid needs

- Frequent and regular performance assessments:
  - Consider program enrollment rates and performance relative to third party commitments
  - Proactively identify scaling constraints and continuous improvements for Phase 3

Phase 3: July 2028-June 2030

Annual reporting supports strategic planning and performance improvement

Phase 3: July 2028-June 2030

- Within four months of the end of each program year in T3, utilities file annual reports that document:
  - Performance across events in terms of demand reductions, enrollment levels, device connectivity, resource availability, and participation rates
  - Strategies to address performance issues

- Utilities update strategies to achieve goals in second and third year of T3 considering:
  - Performance documented in annual report
  - Acquisition cost by customer group
  - Incentive design
  - Impacts of customer dual participation in PJM wholesale markets

- Utilities share performance reports automatically and shortly after events to the BPU, third party program implementers, and PJM

- Utilities make performance-based adjustments to third-party DF commitments as events are called based on reporting, including test events when needed to ensure that resources perform under varying conditions

DER Registry and Orchestration provide foundational infrastructure for program growth

Phase 3: July 2028-June 2030

- The DER Registry serves as a “single source of truth” that provides up-to-date, validated resource enrollment information with limited manual effort to:
  - DER orchestration platform
  - Interconnection processes
  - Third-party DR providers
  - PJM
  - Aggregators
  - Utility distribution system planners

- The Registry automatically receives data on customers who enroll in utility programs and are part of PJM DER aggregations

- DER Orchestration platform is integrated with all retail programs, continues to onboard devices as customers enroll, and supports distribution system-level dispatches in NWAs

Scope of third party programs expands

Phase 3: July 2028-June 2030

- Utilities establish contracts and partnerships with multiple third-party providers as they scale up peak demand reductions, including but not limited to:
  - C&I DR aggregators
  - Residential DR aggregators
  - EV and EV charging manufacturers
  - Smart thermostat makers
  - Battery storage and solar providers
  - Emerging technology providers (e.g., grid-interactive water heaters, smart panels, etc.)

- Utilities make performance-based adjustments to third-party commitments as events are called, including tests that ensure that resources perform under varying conditions

- Utilities use DER Orchestration platform to manage conflicting dispatches between retail programs and PJM DER aggregations

Utilities implement NWAs and evaluate performance

Phase 3: July 2028-June 2030

- Implementation of selected NWA projects occurs between July 2028 and June 2029
- NWAs address grid needs and utilities assess performance between July 2029 and July 2030
- Utilities use DER Orchestration System to prevent conflicting dispatches from NWA, third party-implemented retail programs, and DER aggregations in PJM wholesale markets

Utilities file T4 plans

Phase 3: October 2028

- BPU sets demand reduction goals based on updated demand response potential study
- Utilities develop cost-effective program designs using updated avoided cost study and performance data from T3 programs

Capabilities at the end of phase 3

Phase 3: July 2028-June 2030

- Flexible resources can respond to distribution system grid constraints through NWAs
- Established third-party DR ecosystem integrates a wide range of DER aggregators and devices, particularly those with the largest market potential based on DER adoption data and near-term forecasts
- DER Orchestration platform onboards program devices and aggregations through an automated, user-friendly process with minimal administrative burden for EDCs, participants, and third-parties
- DER Orchestration platform and DER Registry have accurate and granular data and enable DR that address grid needs
- Frequent and regular performance assessments:
  - Consider program enrollment rates and performance relative to third party commitments
  - Proactively identify scaling constraints and continuous improvements for Phase 3