

MMU Review of 2025-2044 System & Resource Outlook

Presented by:

Pallas LeeVanSchaick
Joe Coscia
NYISO Market Monitoring Unit

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Introduction

- The Tariff requires that a copy of the Outlook study be provided to the MMU for its review and consideration
 - We performed an analysis of data from the 2025-2044 Outlook study
- This presentation highlights that:
 - Allowing limited use of gas-fired generation (by requiring 95% rather than 100% emission-free) reduces costs dramatically
 - The NYISO markets provide key economic signals to guide investment in renewable storage resources
 - There are opportunities to improve the Outlook models and processes
- Further details of the results and methodology can be found in the appendix to this presentation

Cost Savings from Allowing Limited Use of Fossil-Fueled Generation

- The Outlook highlights the need for firm dispatchable capacity, potentially including new or repowered fossil units
 - Adding and/or retaining some fossil-fueled units for reliability avoids the need for very large amounts of additional hydrogen/storage capacity
- By 2044, we estimate that levelized investment costs, fixed costs, and production costs in the 100x44 case (baseline load) exceed the 95x44 case by **~\$15 billion per year** (\$2025, MMU estimate, see slide [44](#))
 - This is equivalent to **\$1,500 per ton** of difference in CO₂ emissions
- The official ‘zero emissions by 2040’ requirement has had major market impacts through higher ICAP demand curves, denial of repowering proposals, and lack of new project proposals
 - Clarification of the long-term role of fossil-fueled capacity would have major benefits to the market and consumers

Evaluating Curtailment and Investment Incentives

- The Outlook report provides for each scenario:
 - Total curtailment of renewables; and
 - Average curtailment rates.
- We use data from the Outlook PLEXOS cases to evaluate market incentives and the comparative marginal cost of supplying clean energy from various technologies

Case	Base Case	Incremental Additions		
		Contract	100x44 - High Demand	95x44 - Baseline Demand
Analysis Year	2030	2030	2035	2035
Average Load (GW)	18.5	18.5	23.4	20.2
<u>Modeled Additions (GW):</u>				
Solar PV	2.4	3.3	27.6	7.5
Land Based Wind	3.2	0.6	11.7	9.7
Offshore Wind	1.7	0.0	2.8	0.0
Energy Storage	0	0.0	6.3	0.4

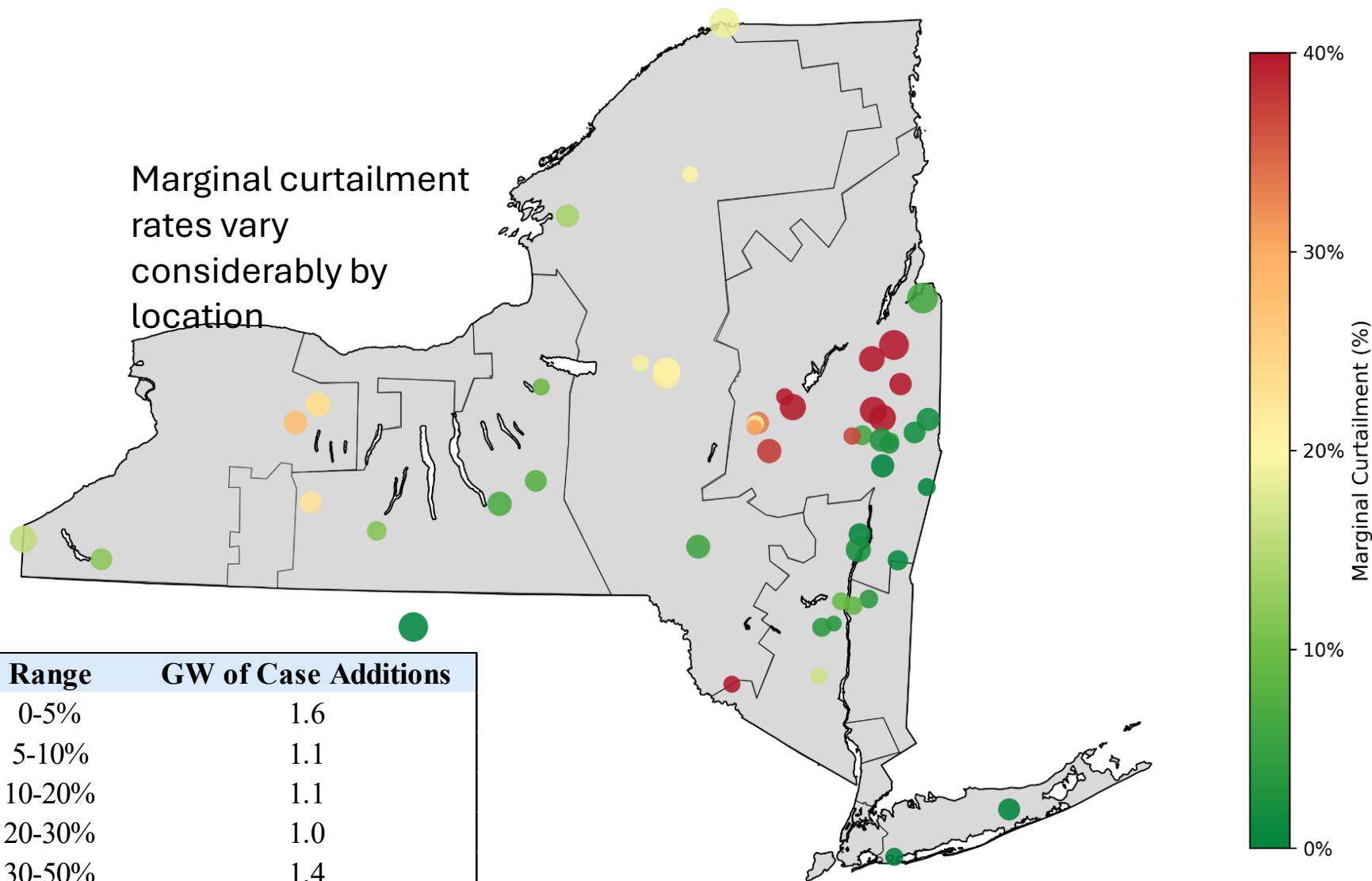
MMU Metrics for Analyzing Curtailment and Investment Incentives

- We evaluate Outlook model results using these metrics:
 - *Marginal Curtailment Rate* – Share of an incremental renewable unit's generation that would result in curtailment;
 - *Technology Discount and Nodal Discount* – Difference between zonal average LBMP and generation-weighted zonal or nodal averages;
 - *Renewable Deliverability Improvement* – Number of MWh of curtailment avoided per MW of additional storage per year;
 - *Implied Net REC Cost* – The net cost of incremental renewable energy deliveries from an investment in generation, storage, or transmission.

Marginal Curtailment Rate

95x44 Baseline Load 2035 – Solar PV

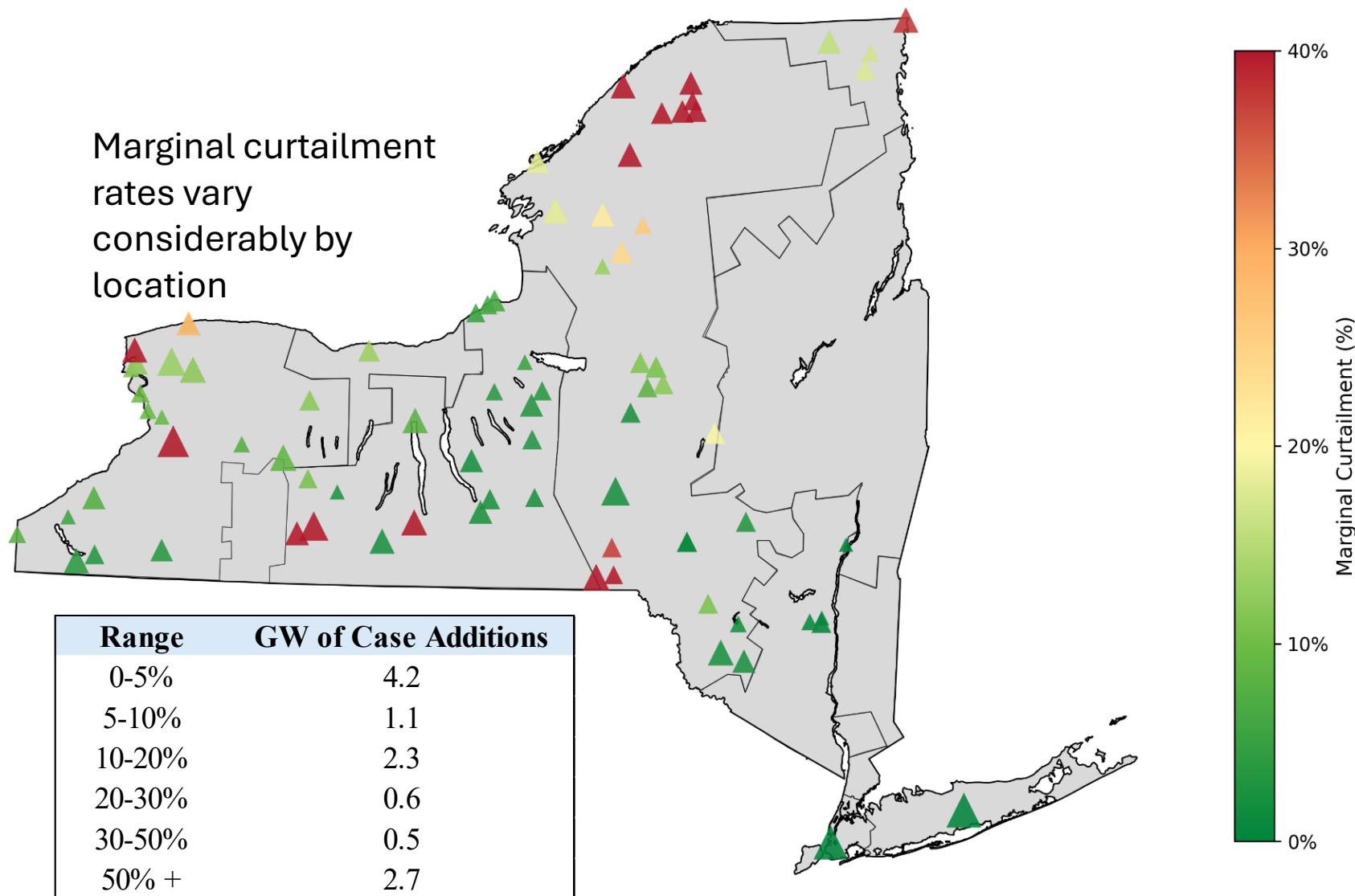
Marginal curtailment rates vary considerably by location



Range	GW of Case Additions
0-5%	1.6
5-10%	1.1
10-20%	1.1
20-30%	1.0
30-50%	1.4
50% +	1.3

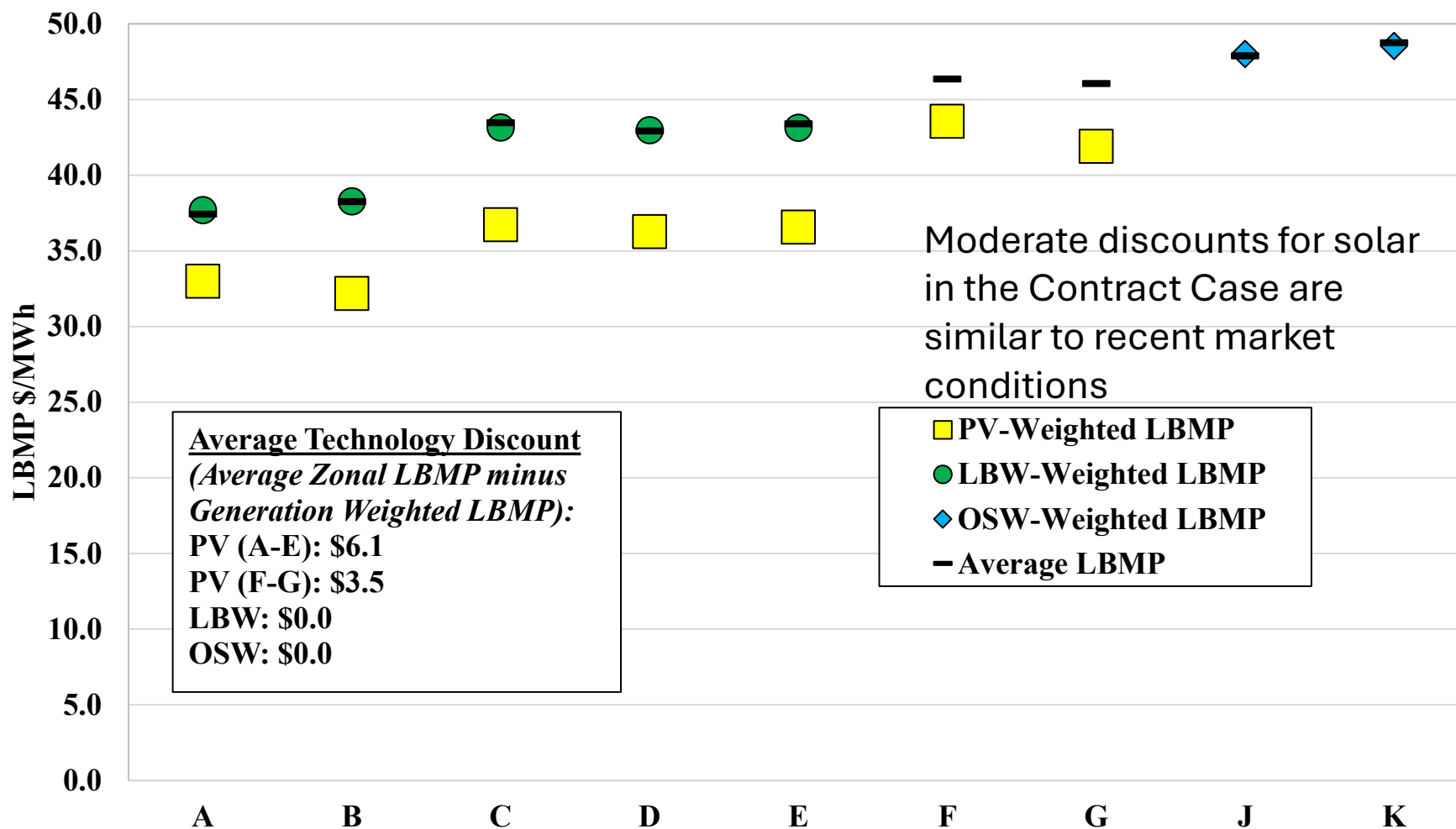
Marginal Curtailment Rate 95x44 Baseline Load 2035 – Wind

Marginal curtailment rates vary considerably by location



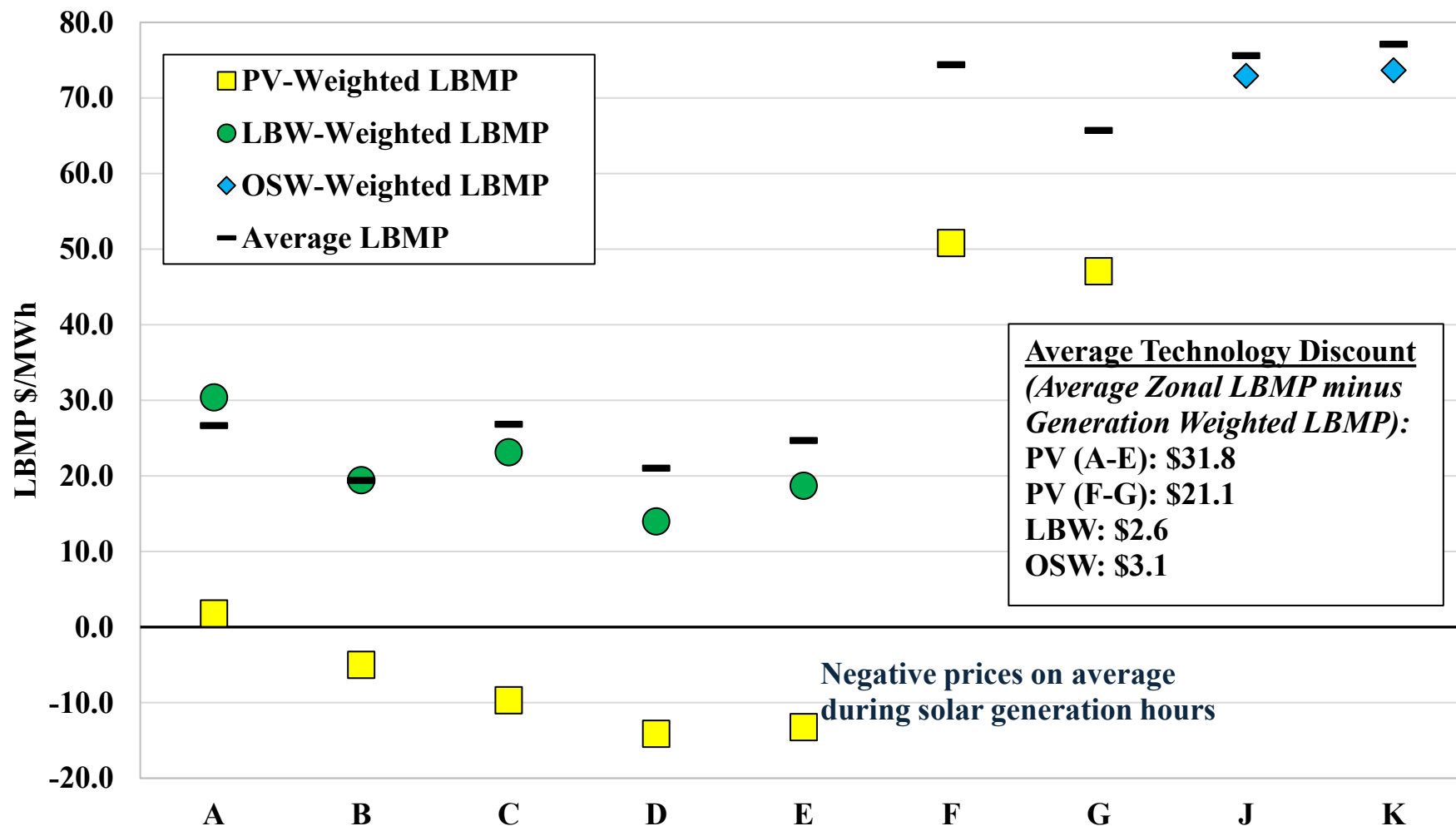
Technology Discounts by Zone

Contract Case 2030



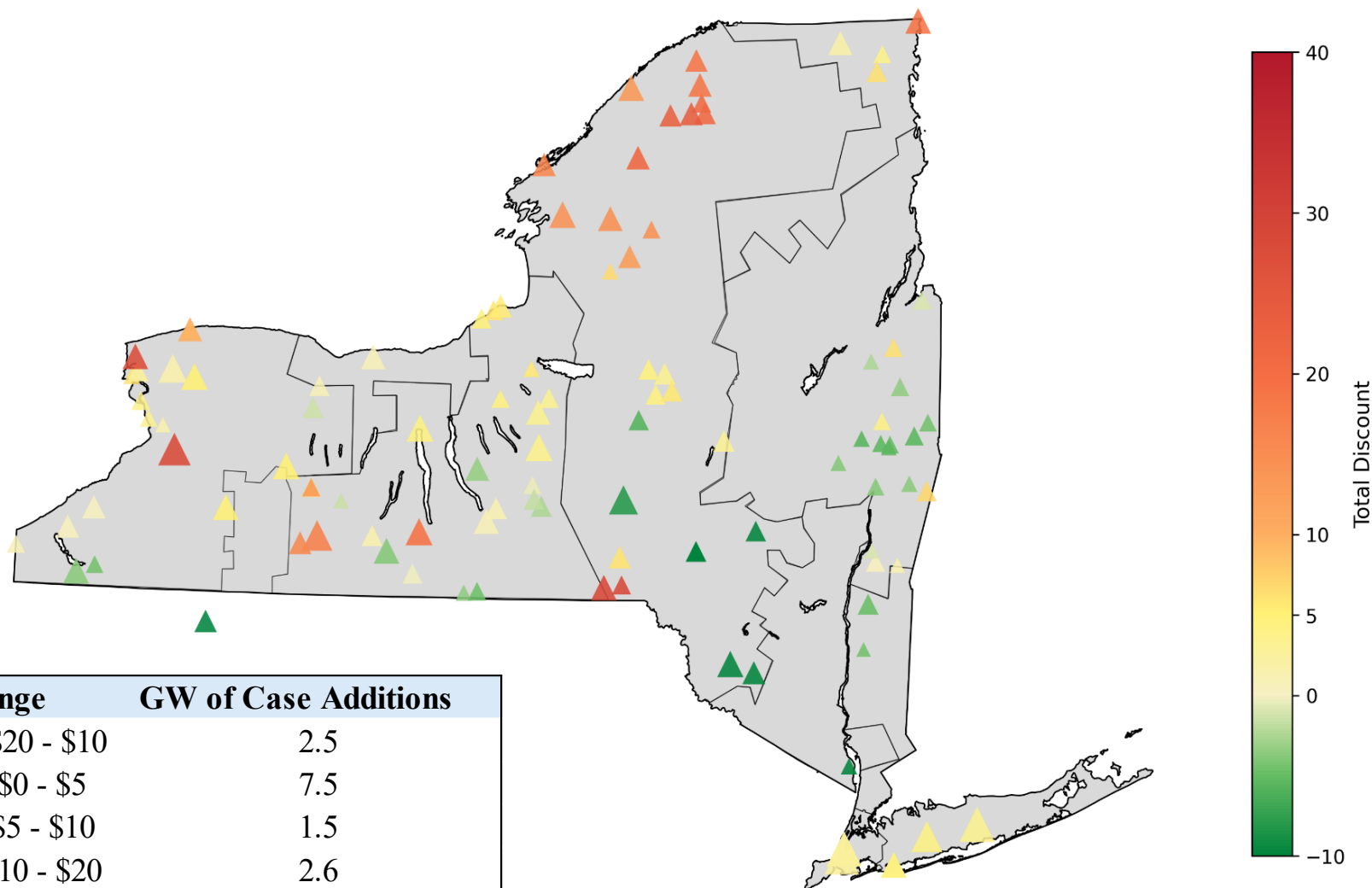
Technology Discounts by Zone

100x44 High Load 2035



Nodal and Technology Discount

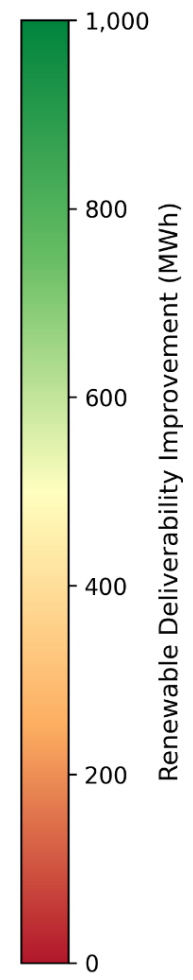
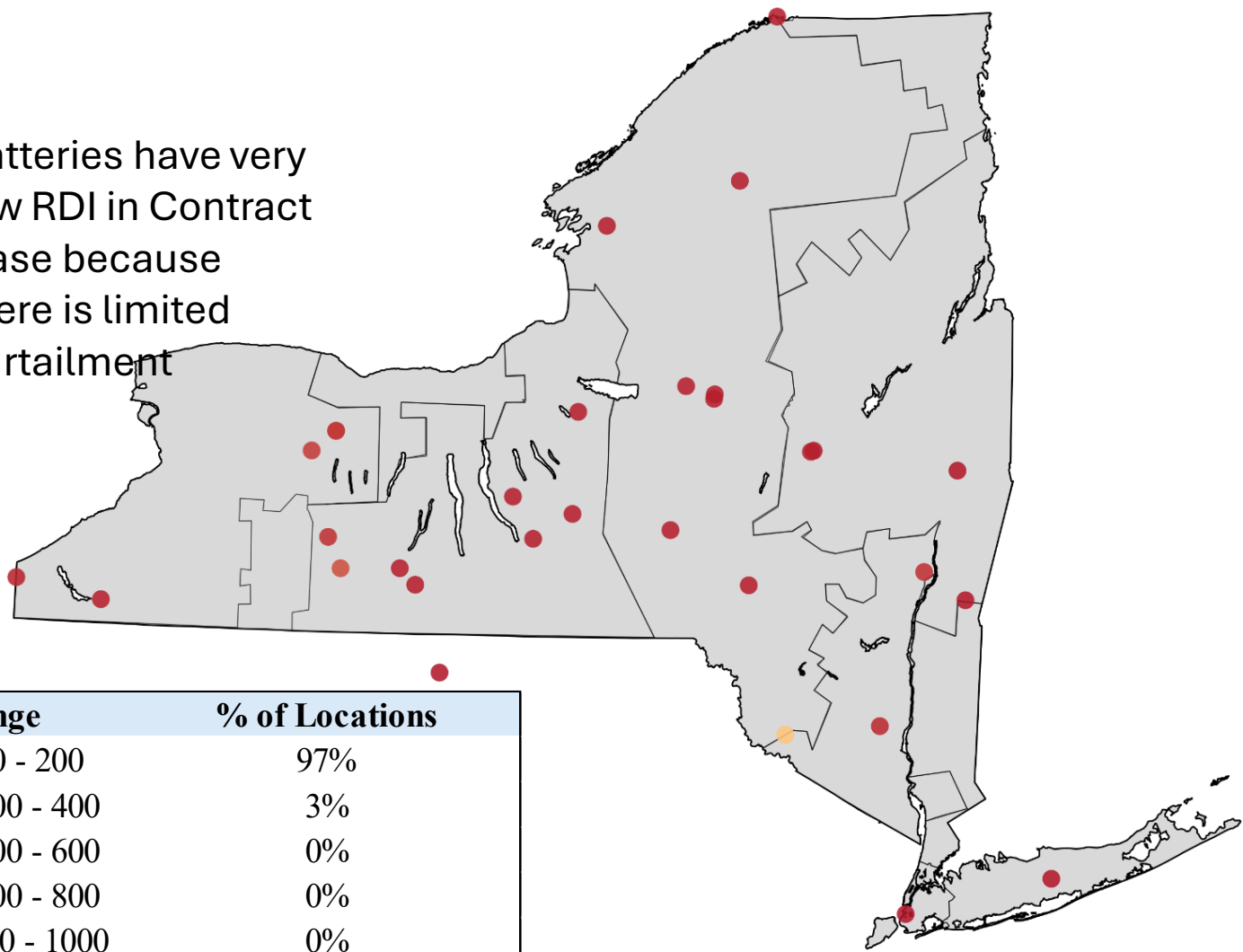
100x44 High Load 2035 – Wind [table to include \$s]



Range	GW of Case Additions
-\$20 - \$10	2.5
\$0 - \$5	7.5
\$5 - \$10	1.5
\$10 - \$20	2.6
\$20 - \$30	1.8
\$30 - \$100	0.0

Renewable Deliverability Improvement Contract Case 2030 – 4 Hour Battery

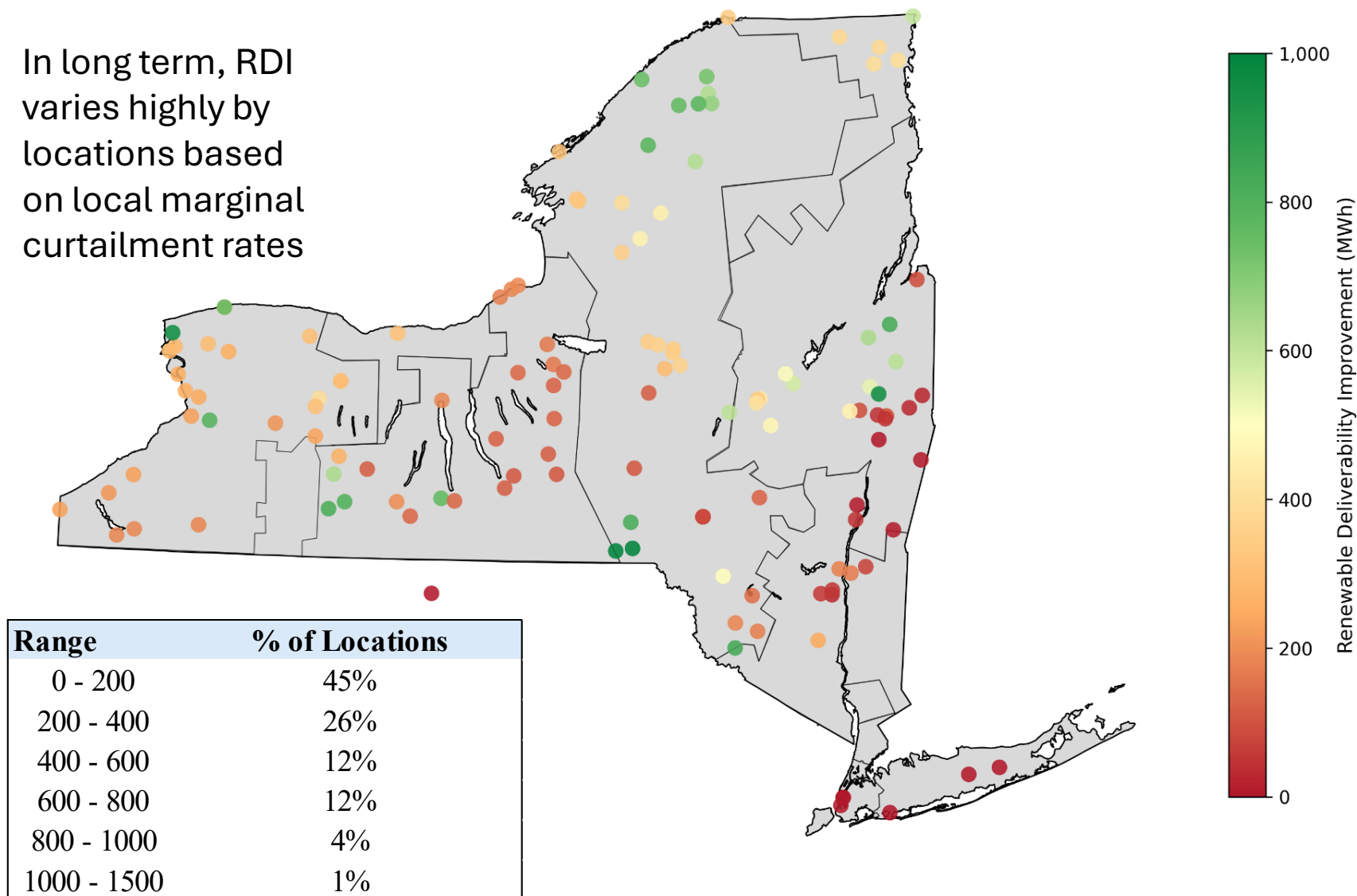
Batteries have very low RDI in Contract Case because there is limited curtailment



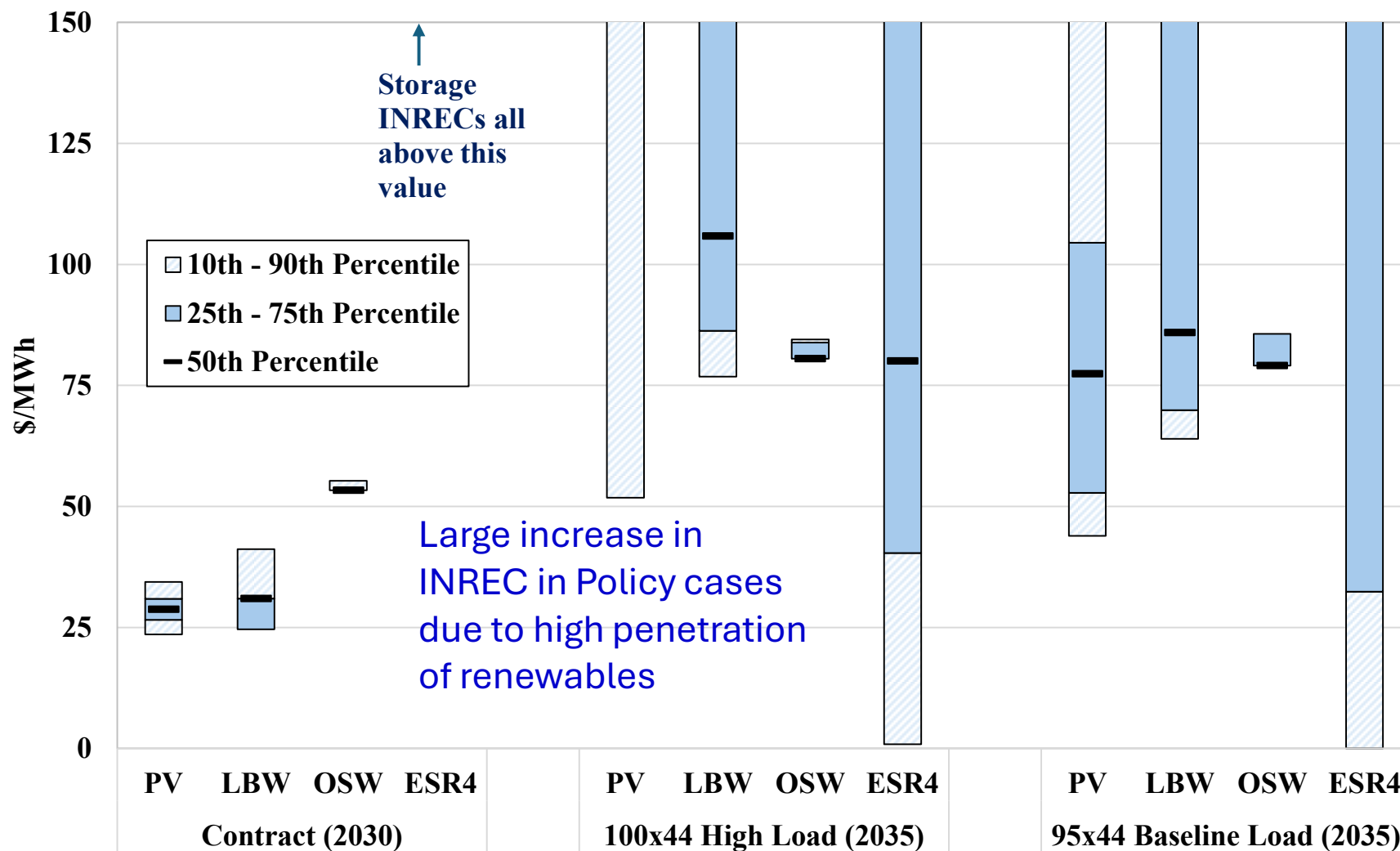
Range	% of Locations
0 - 200	97%
200 - 400	3%
400 - 600	0%
600 - 800	0%
800 - 1000	0%
1000 - 1500	0%

Renewable Deliverability Improvement 95x44 Baseline Load 2035 – 4 Hour Battery

In long term, RDI
varies highly by
locations based
on local marginal
curtailment rates



Implied Net REC Costs by Technology and Case



Conclusions

- The Outlook study results highlight the critical role of NYISO market signals in guiding renewable and storage investment
- Wind and solar:
 - At financial risk due to technology and nodal discounts
 - Under Index REC structure, NYISO markets provide strong incentives to build at deliverable locations
- Energy Storage
 - Not cost-effective for improving REC supply when curtailment rates are low; can be economic as wind/solar increases
 - Under Index Storage Credit structure, strong incentives to seek out areas with greatest potential to mitigate curtailment
 - Unlikely to be profitable near profitable renewable generator sites

Key Recommendations

- P19-6: Consider transmission outages and day-ahead net load forecast error when estimating production costs and curtailment.
 - Current models may under-estimate congestion and curtailment of renewables in near-term cases with realistic renewables quantities
- P22-2: Perform ‘optimized’ production cost run relocating resources placed at locations with high marginal curtailment if possible
 - 2025 Outlook improved resource siting methodology, but some cases appear to place outsized generation amounts at constrained POIs (e.g. 95x44 case in 2035)

Appendix

Methodology and Results Details

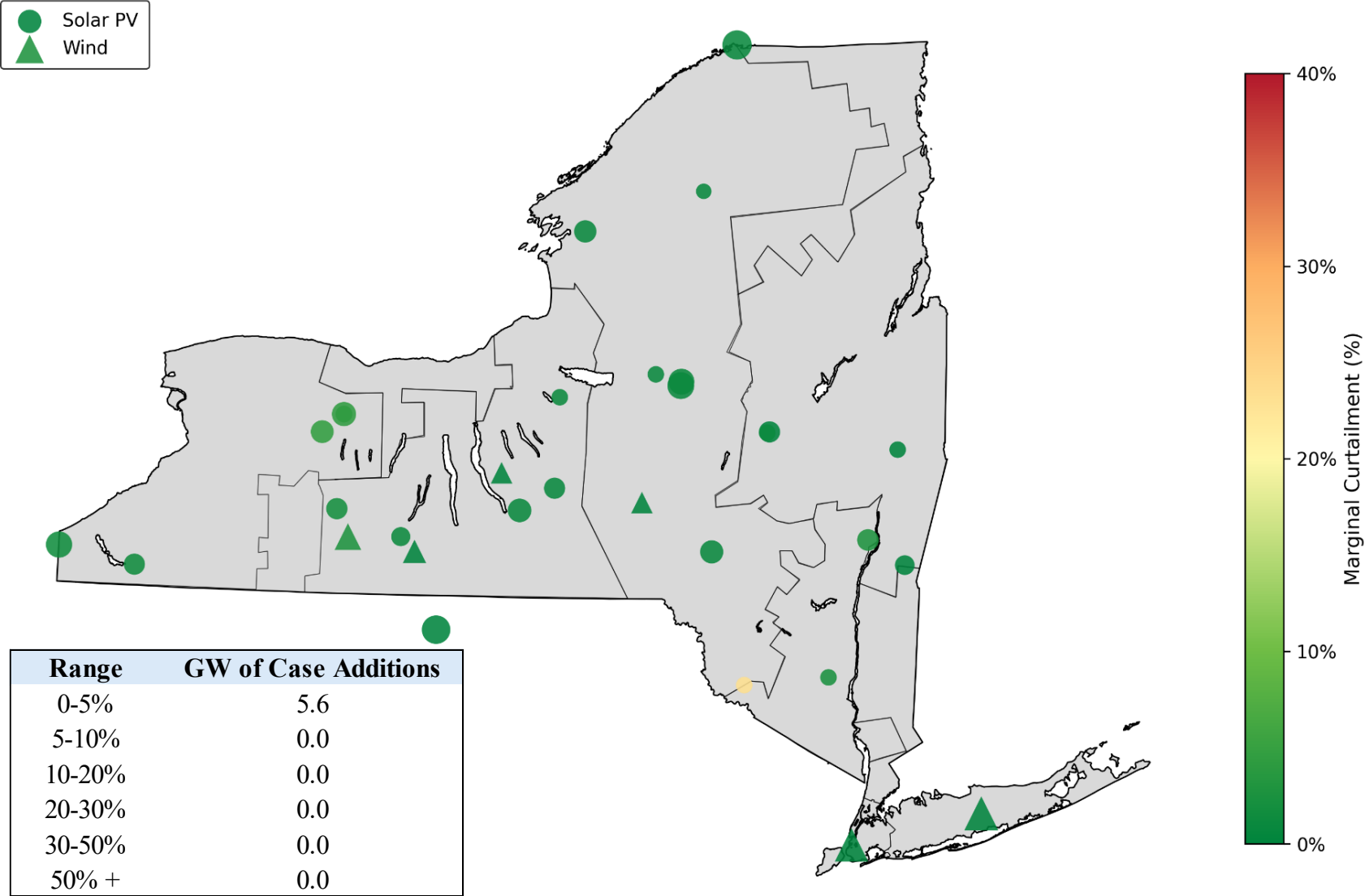
Analysis of Curtailment and Net Revenues

- The following slides discuss and present results for each of the following at various locations:
 - Marginal Curtailment Rate – percentage of an incremental renewable unit's generation that would result in curtailment;
 - Technology and Nodal Discount – difference between zonal average LBMP and generation-weighted zonal or nodal averages;
 - Renewable Deliverability Improvement – amount of MWh that an additional MW of storage would save from being curtailed annually;
 - Implied Net REC Cost – The net cost of incremental renewable energy deliveries from an investment in generation, storage, or transmission.
- We use data from the following NYISO PLEXOS cases:
 - Contract Case (2030)
 - 100x44 ("Policy C") case with High Load forecast
 - 95x44 ("Policy D") case with Baseline load (including nuclear build limit)

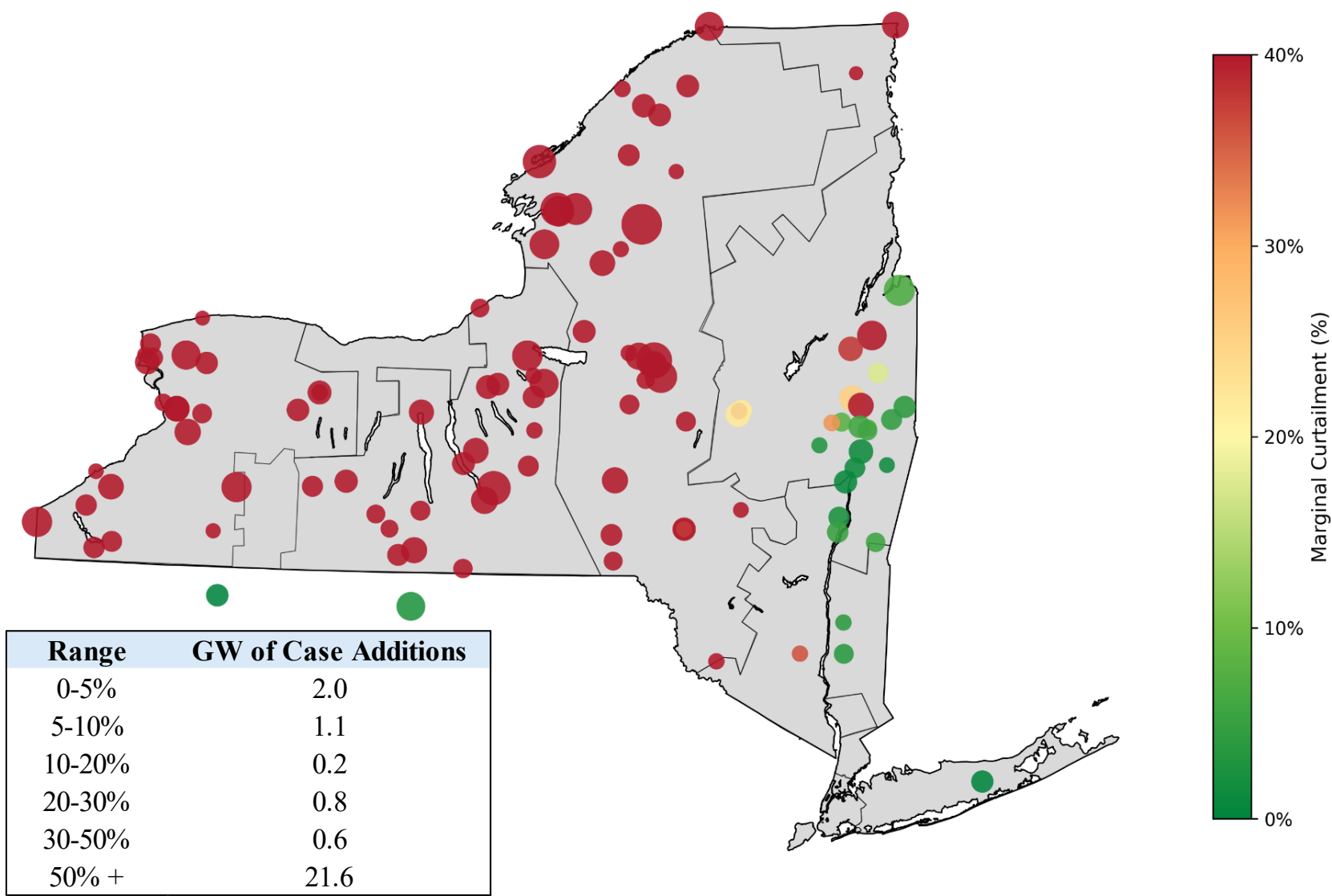
Marginal Curtailment Rate

- Percentage of output from an incremental MW of a renewable resource that would be curtailed or cause other renewable resources to be curtailed.
- Calculated as the percentage of the resource's annual potential generation (based on modeled capacity factor profile) that occurs in hours with LBMP of \$0 or negative.
- For example, output occurring in hour where LBMP is negative \$20 and the resource offers negative \$40 counts as marginal curtailment even though the resource is not curtailed, because it causes curtailment of another negatively priced resource.
- We estimate marginal curtailment rates at locations where incremental wind and solar were included in the Contract and Policy cases.

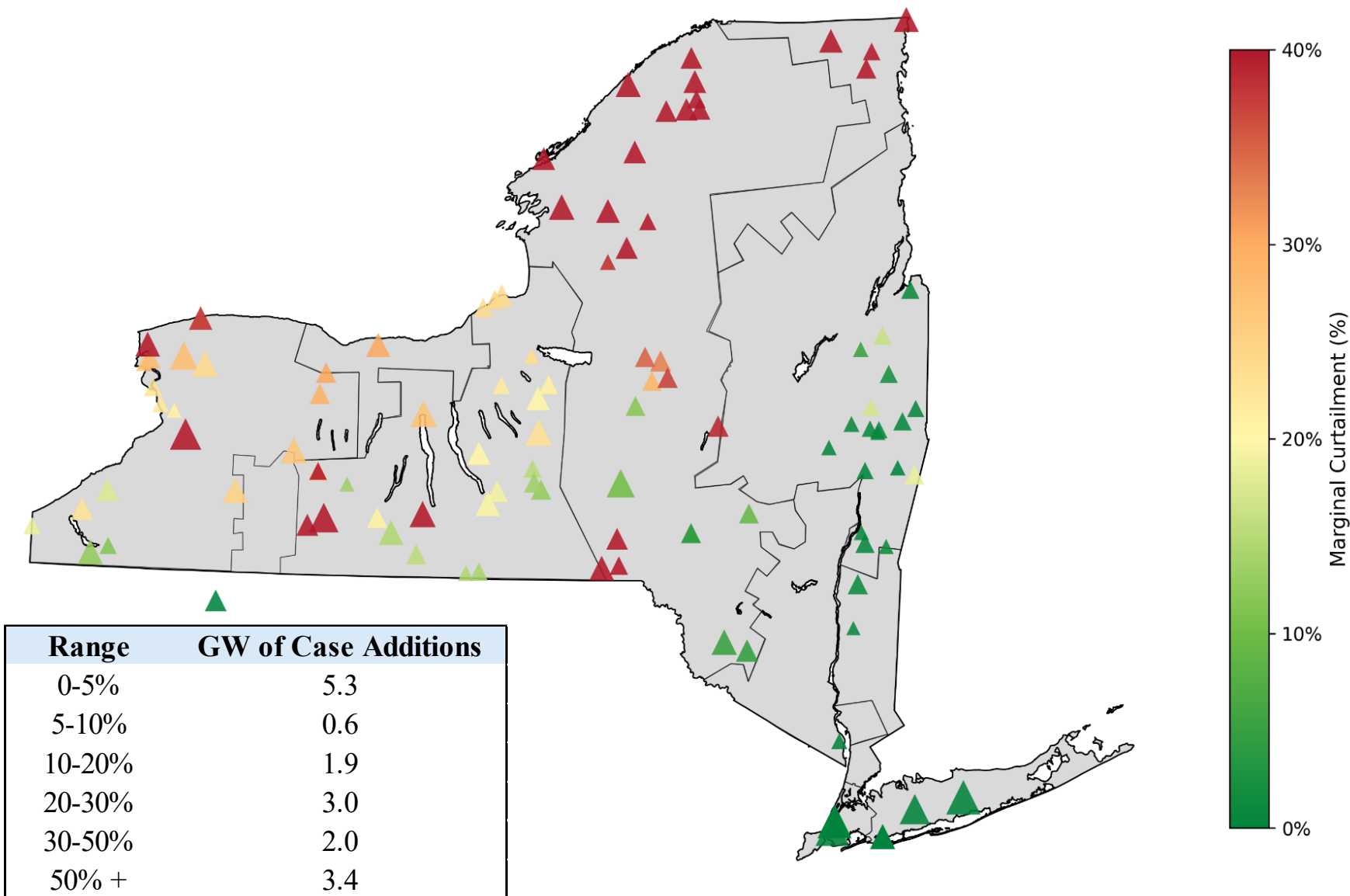
Marginal Curtailment Rate Contract Case 2030



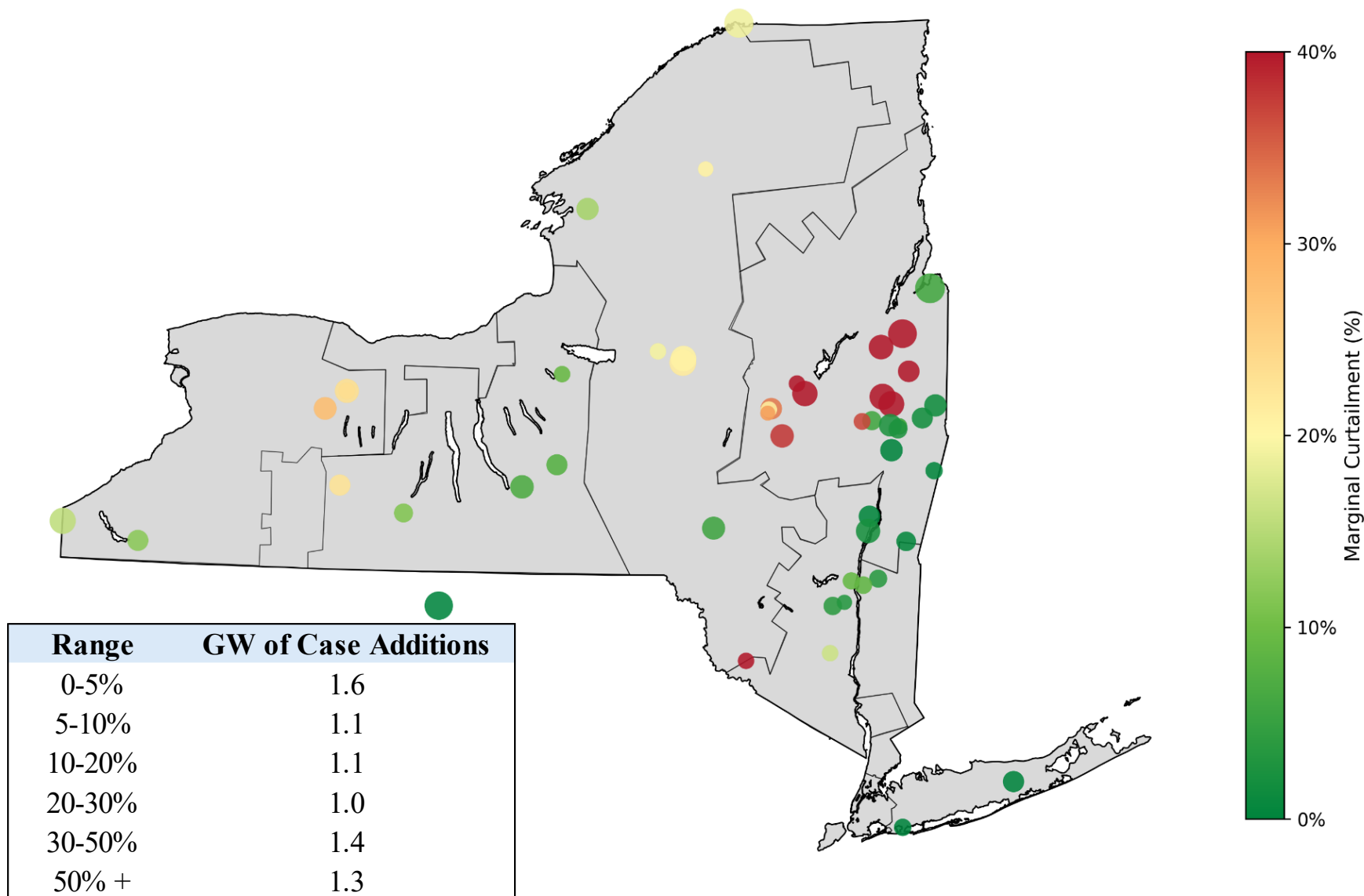
Marginal Curtailment Rate 100x44 High Load 2035 – Solar PV



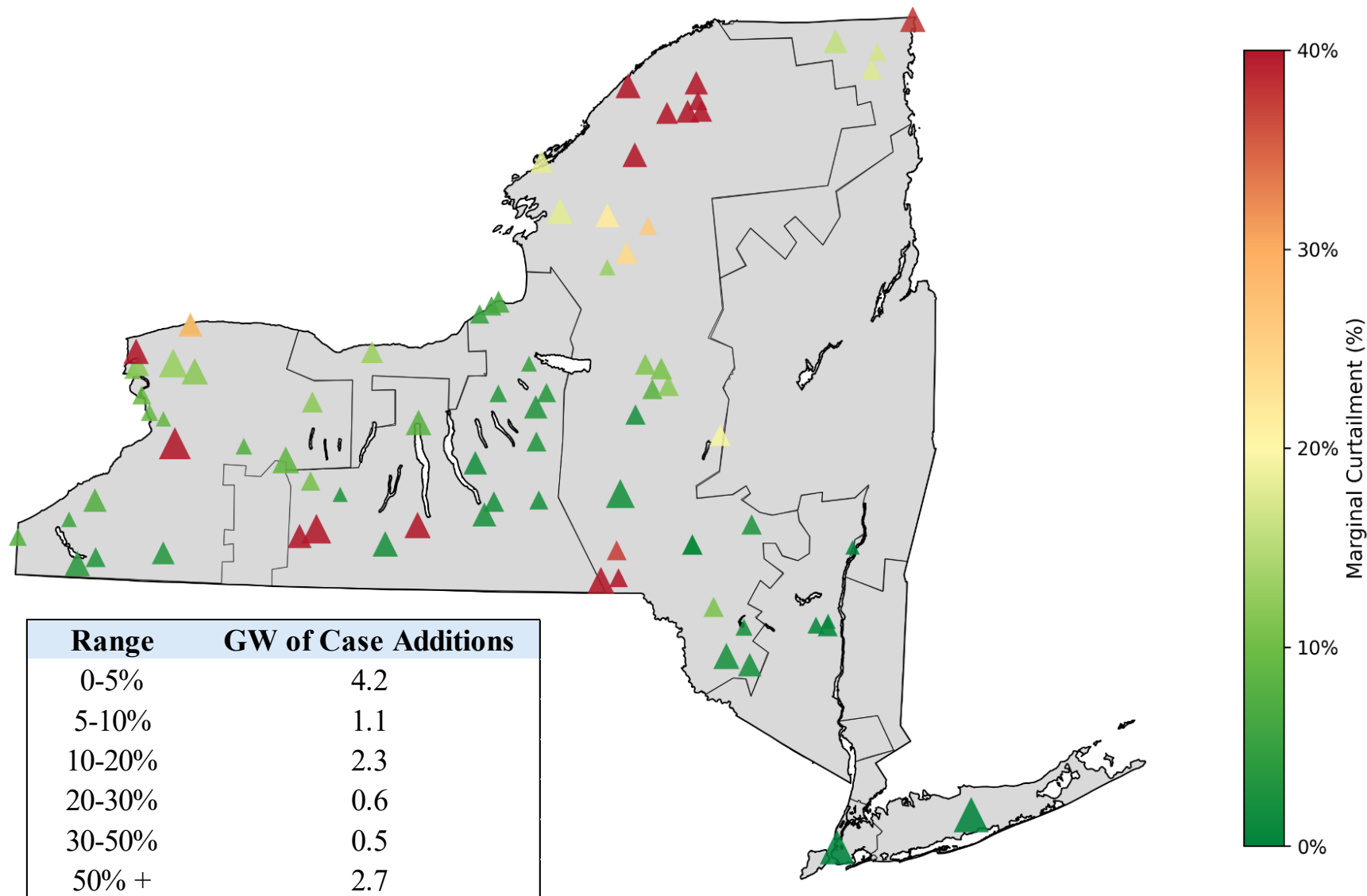
Marginal Curtailment Rate 100x44 High Load 2035 – Wind



Marginal Curtailment Rate 95x44 Baseline Load 2035 – Solar PV



Marginal Curtailment Rate 95x44 Baseline Load 2035 – Wind

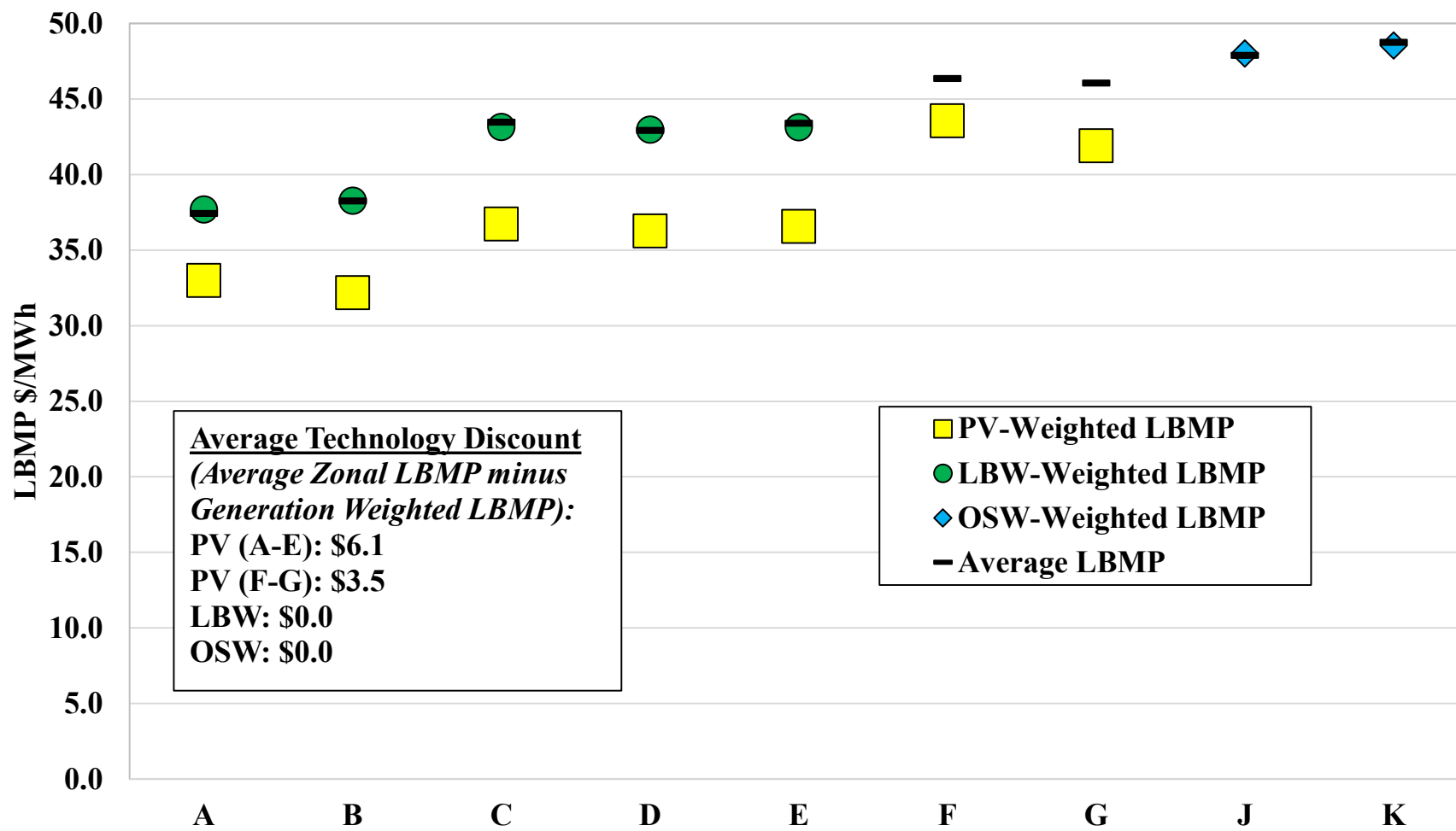


Technology and Nodal Discounts

- Technology Discount Definition:
 - Difference between (1) simple average zonal LBMP and (2) average zonal LBMP weighted by potential generation profile of resource.
- Nodal Discount Definition:
 - Difference between (1) simple average zonal LBMP and (2) average nodal LBMP weighted by potential generation profile of resource.
- Technology and nodal discounts indicate amount by which total revenues of resource (including REC payments) will fall short of Index REC Strike Price.
 - Index REC payments are linked to simple average zonal LBMP
- We estimate nodal discounts at locations where incremental wind and solar were included in the Contract and Policy cases.

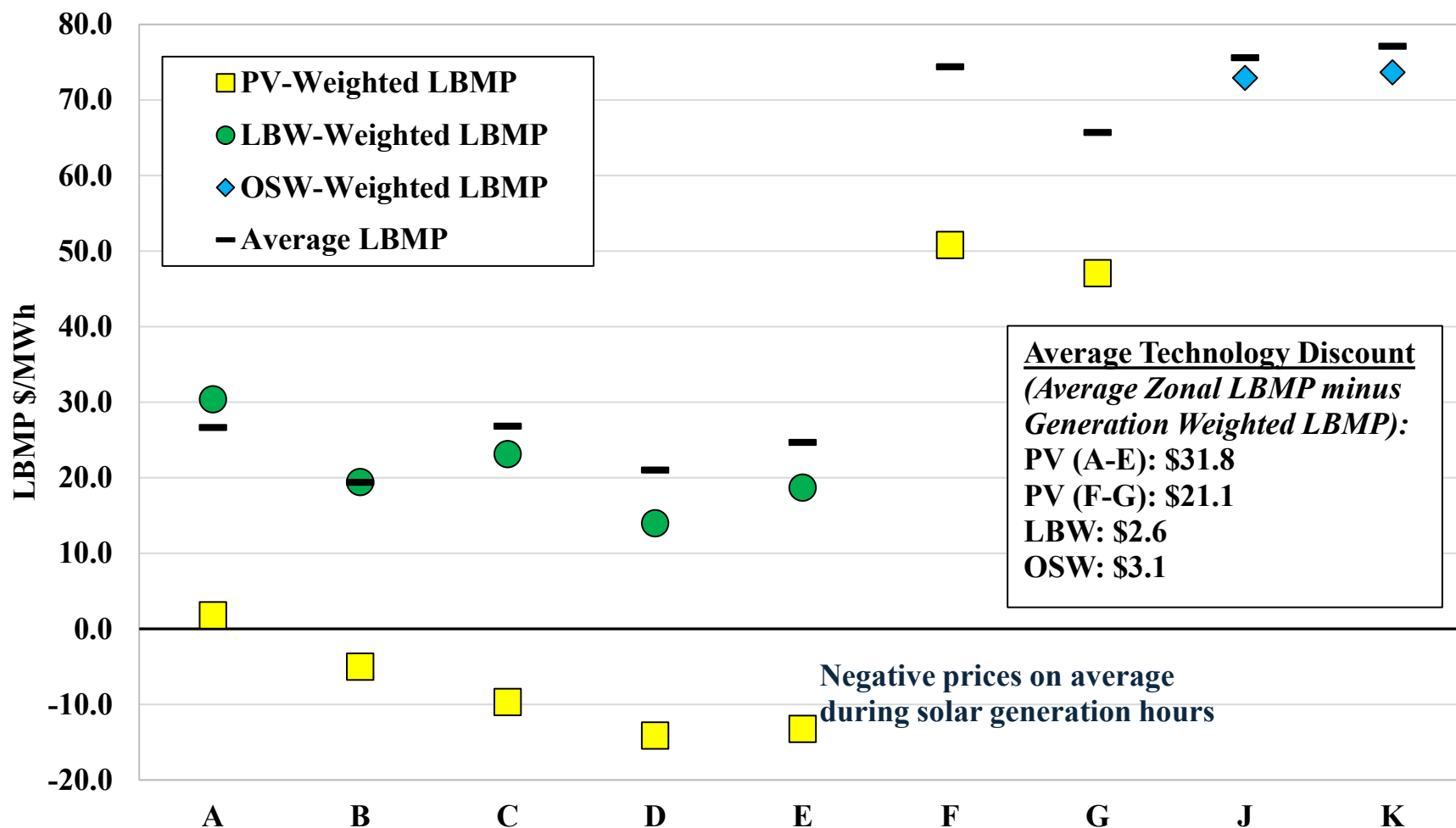
Technology Discounts by Zone

Contract Case 2030



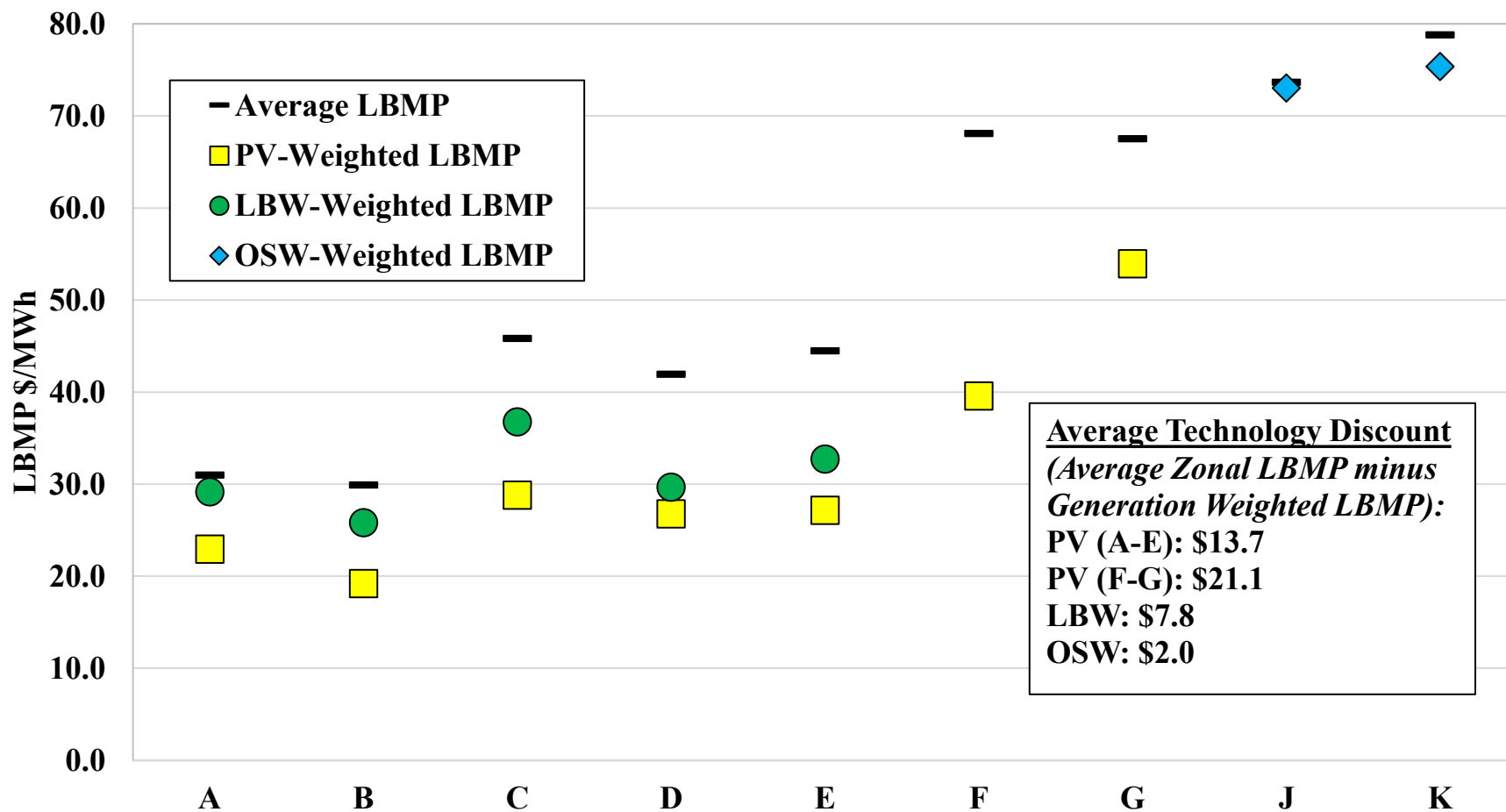
Technology Discounts by Zone

100x44 High Load 2035

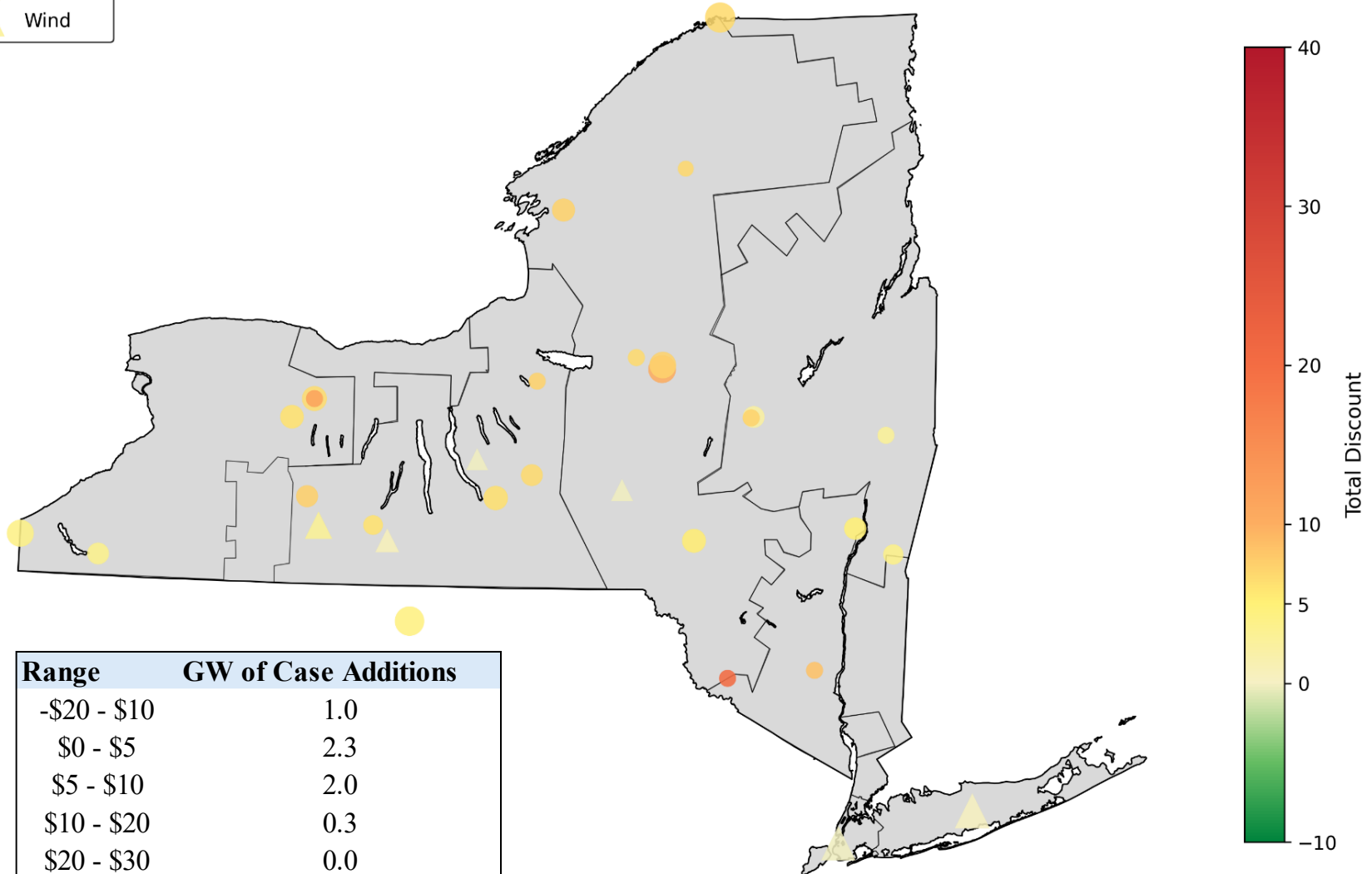


Technology Discounts by Zone

95x44 Baseline Load 2035

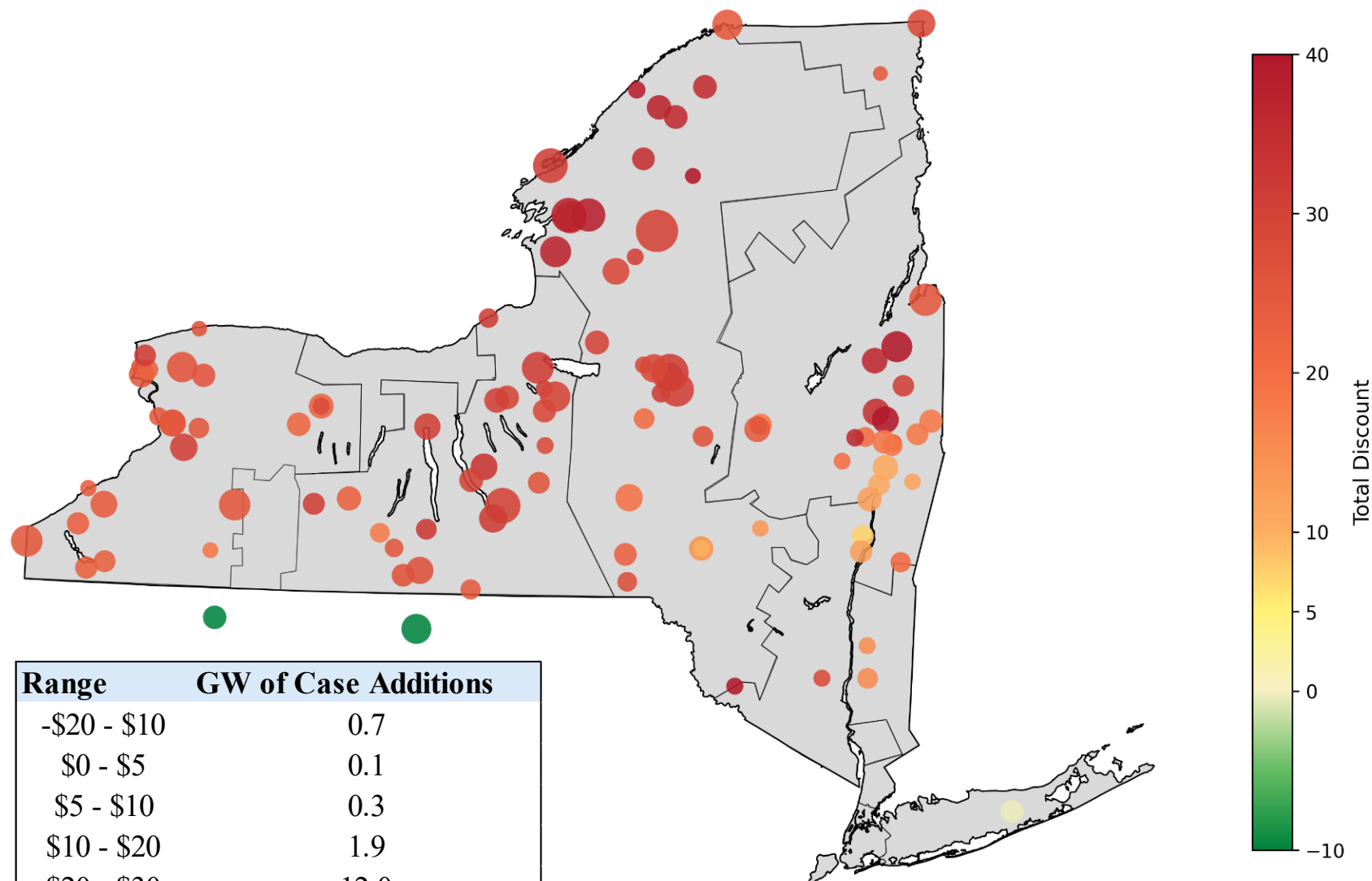


Nodal and Technology Discounts Contract Case 2030



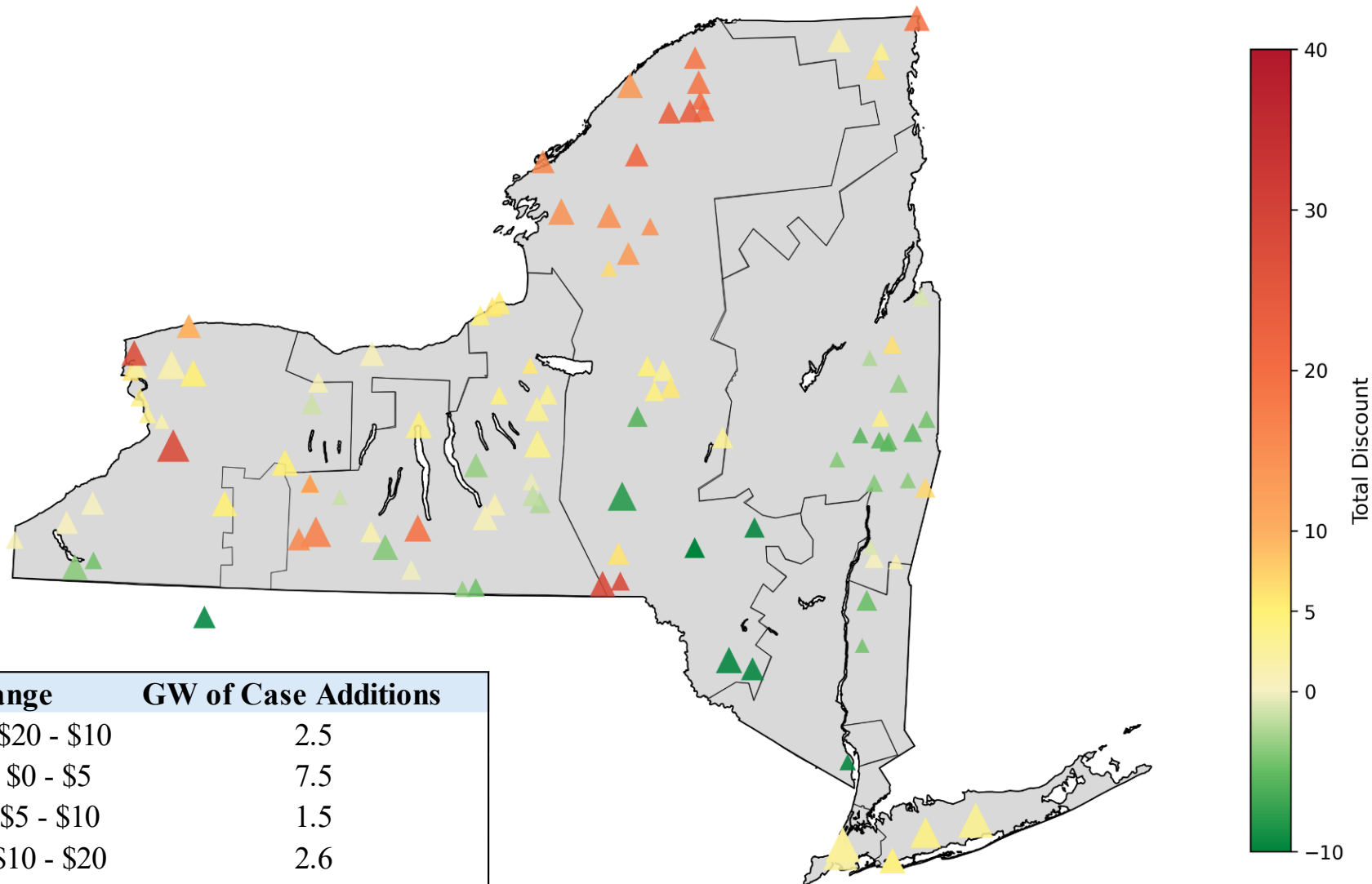
Range	GW of Case Additions
-\$20 - \$10	1.0
\$0 - \$5	2.3
\$5 - \$10	2.0
\$10 - \$20	0.3
\$20 - \$30	0.0
\$30 - \$100	0.0

Nodal and Technology Discount 100x44 High Load 2035 – Solar PV



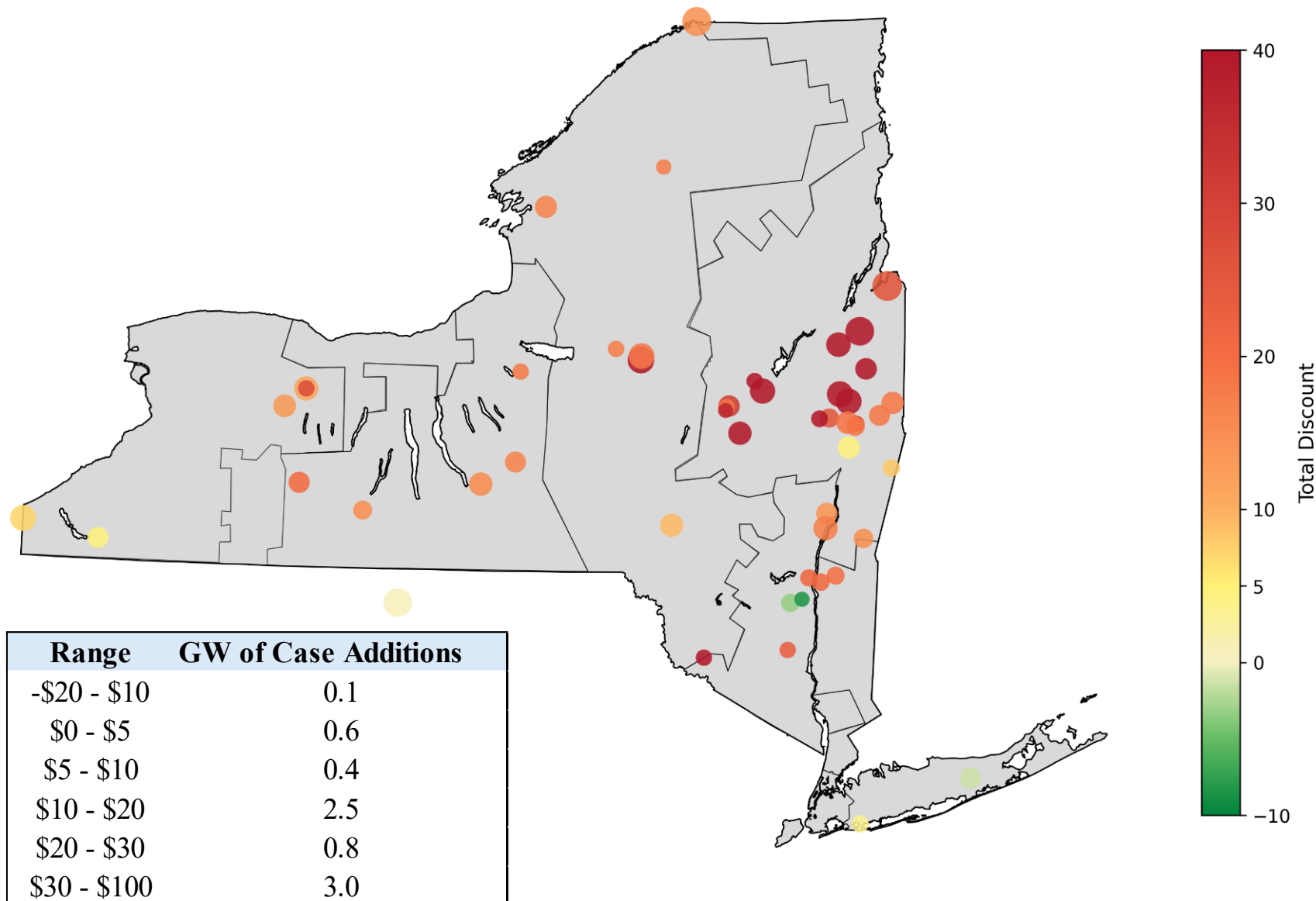
Range	GW of Case Additions
-\$20 - \$10	0.7
\$0 - \$5	0.1
\$5 - \$10	0.3
\$10 - \$20	1.9
\$20 - \$30	12.0
\$30 - \$100	11.2

Nodal and Technology Discount 100x44 High Load 2035 – Wind

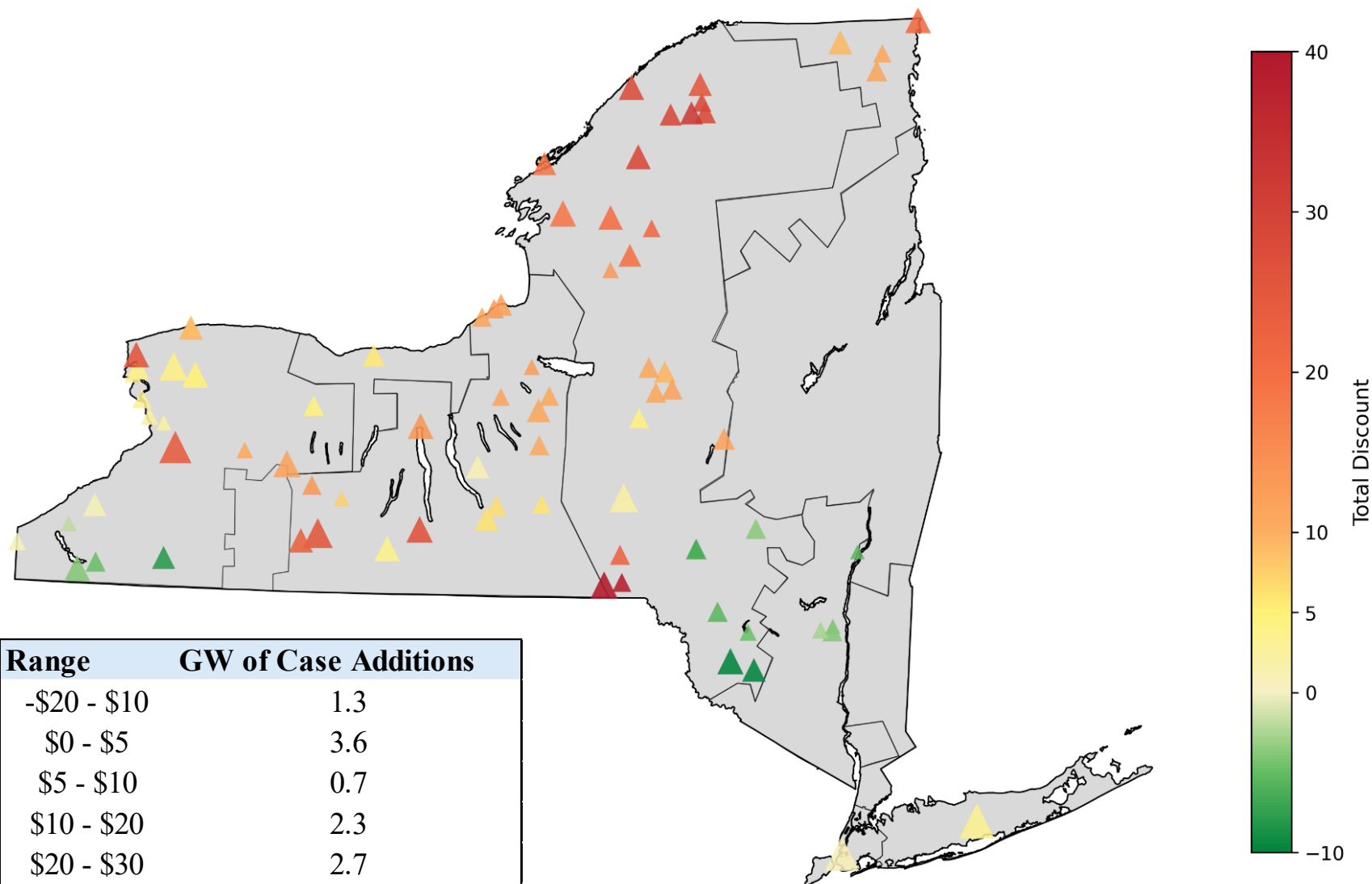


Range	GW of Case Additions
-\$20 - \$10	2.5
\$0 - \$5	7.5
\$5 - \$10	1.5
\$10 - \$20	2.6
\$20 - \$30	1.8
\$30 - \$100	0.0

Nodal and Technology Discount 95x44 Baseline Load 2035 – Solar



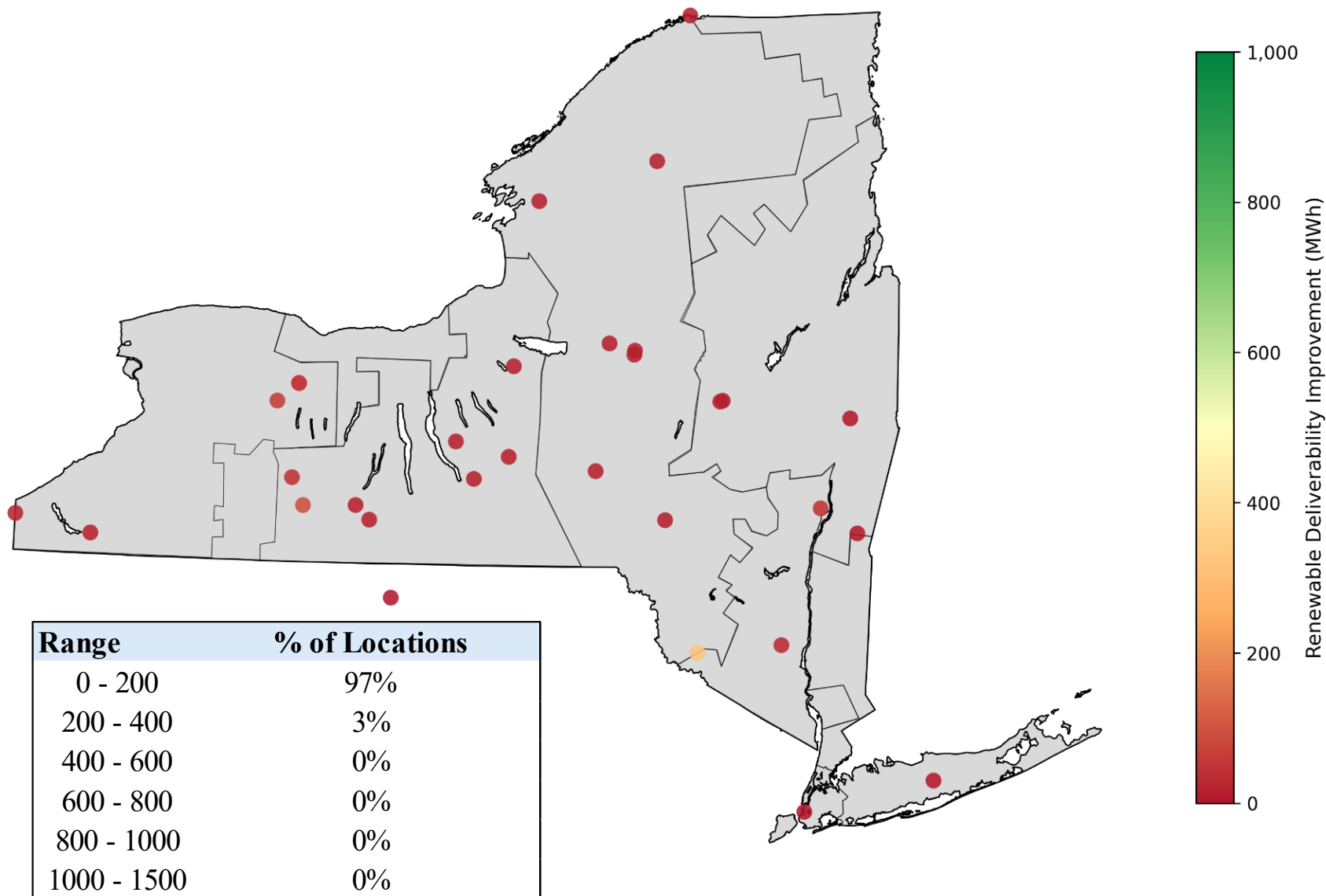
Nodal and Technology Discount 95x44 Baseline Load 2035 – Wind



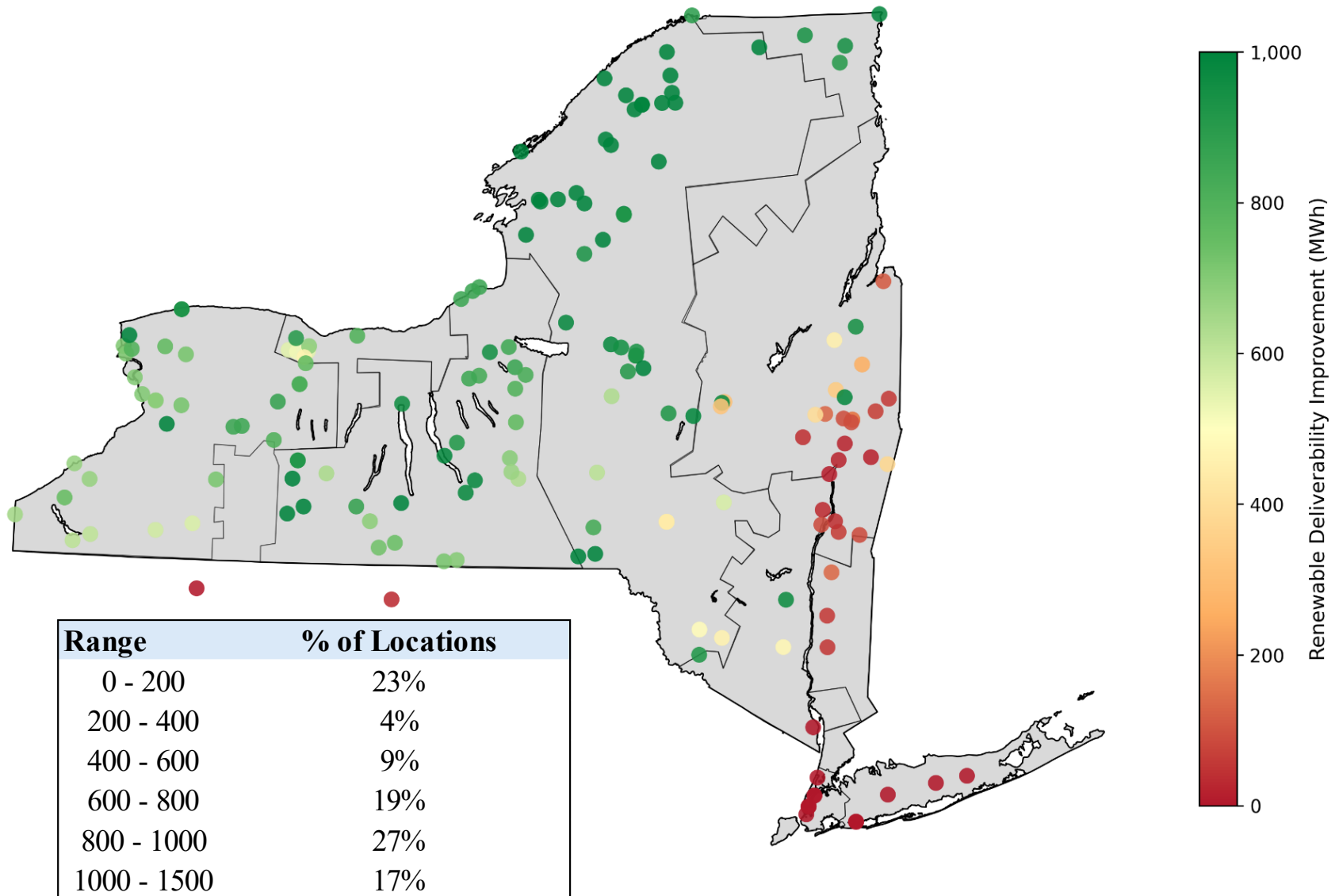
Renewable Deliverability Improvement (RDI)

- Annual MWh of renewable generation that an incremental MW of battery storage capacity would prevent from being curtailed.
- Calculated using a model that optimally charges/discharges battery based on LBMP.
- RDI is the number of hour pairs where a 1 MW battery charges during LBMP of \$0 or negative and discharges during hours with positive LBMP.
- We estimate RDI of storage at buses where renewable additions were included in the Contract and Policy cases.

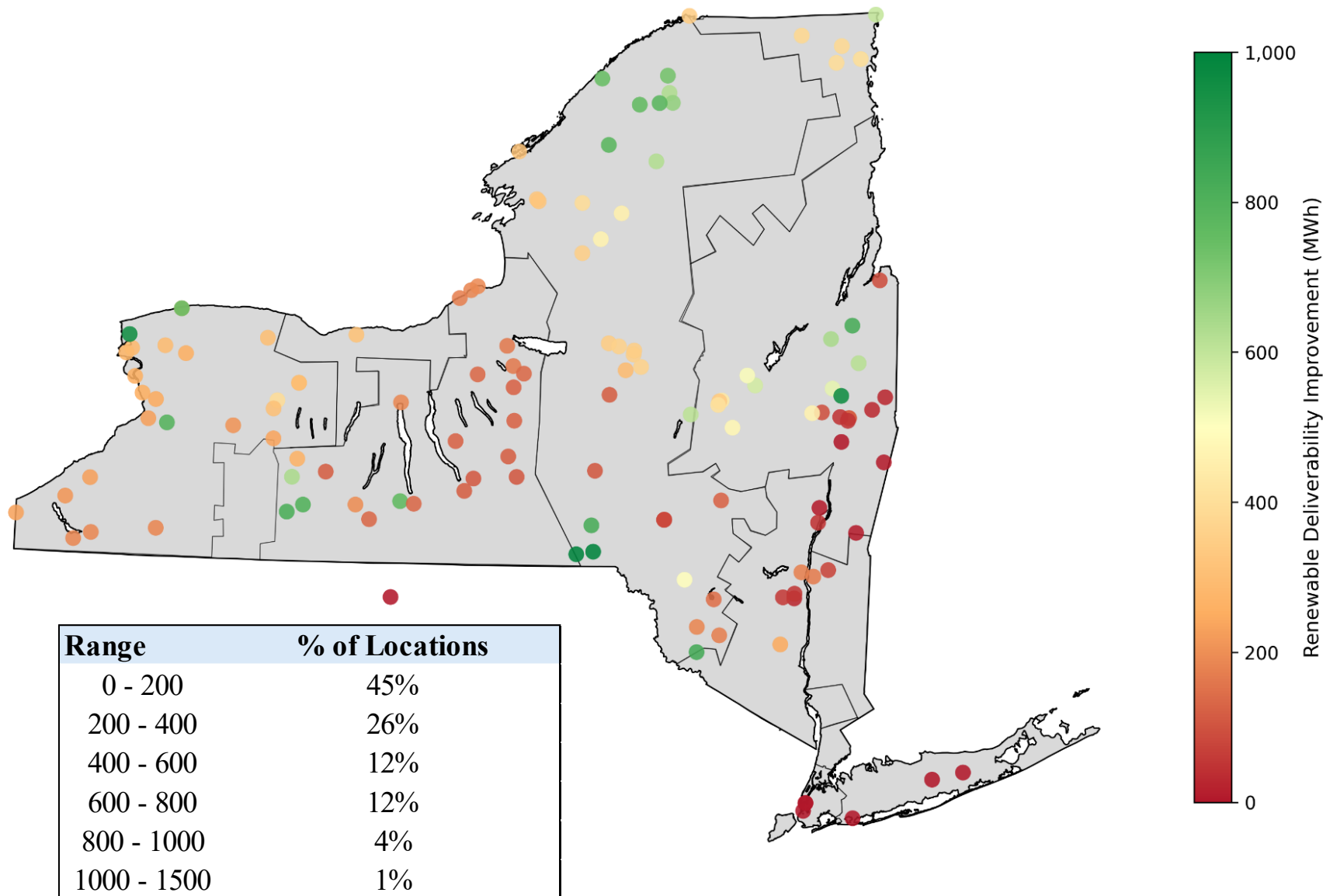
Renewable Deliverability Improvement Contract Case 2030 – 4 Hour Battery



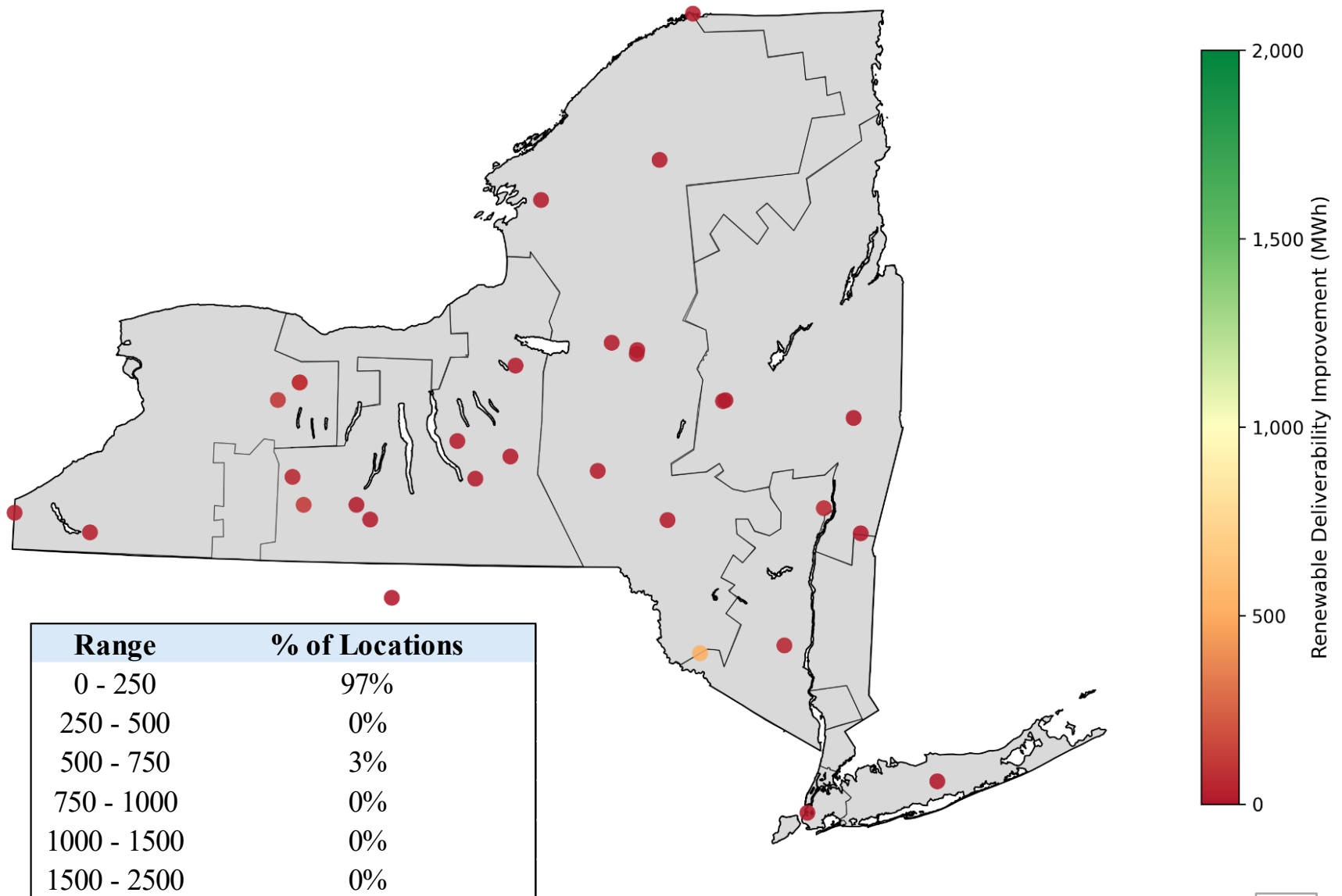
Renewable Deliverability Improvement 100x44 High Load 2035 – 4 Hour Battery



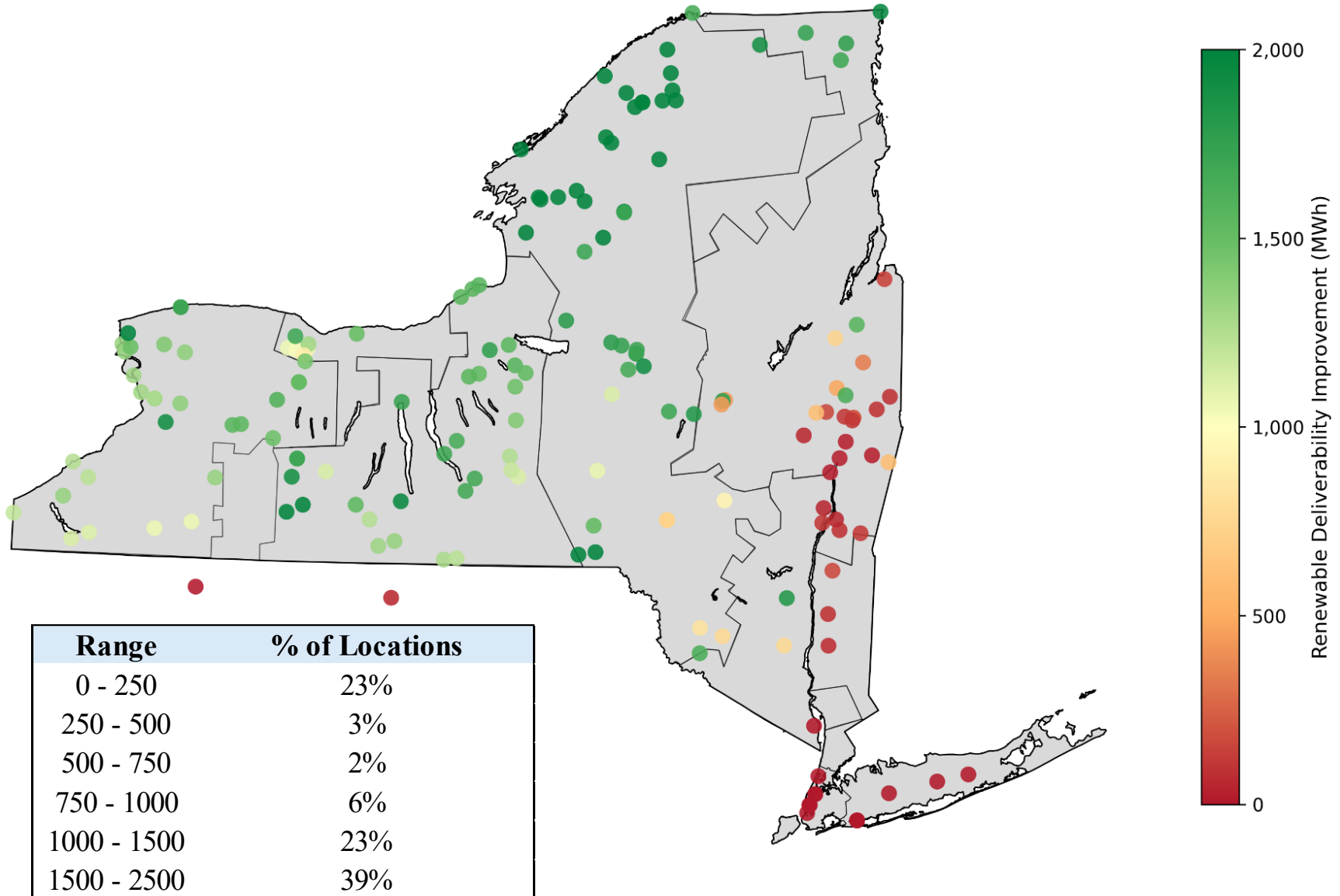
Renewable Deliverability Improvement 95x44 Baseline Load 2035 – 4 Hour Battery



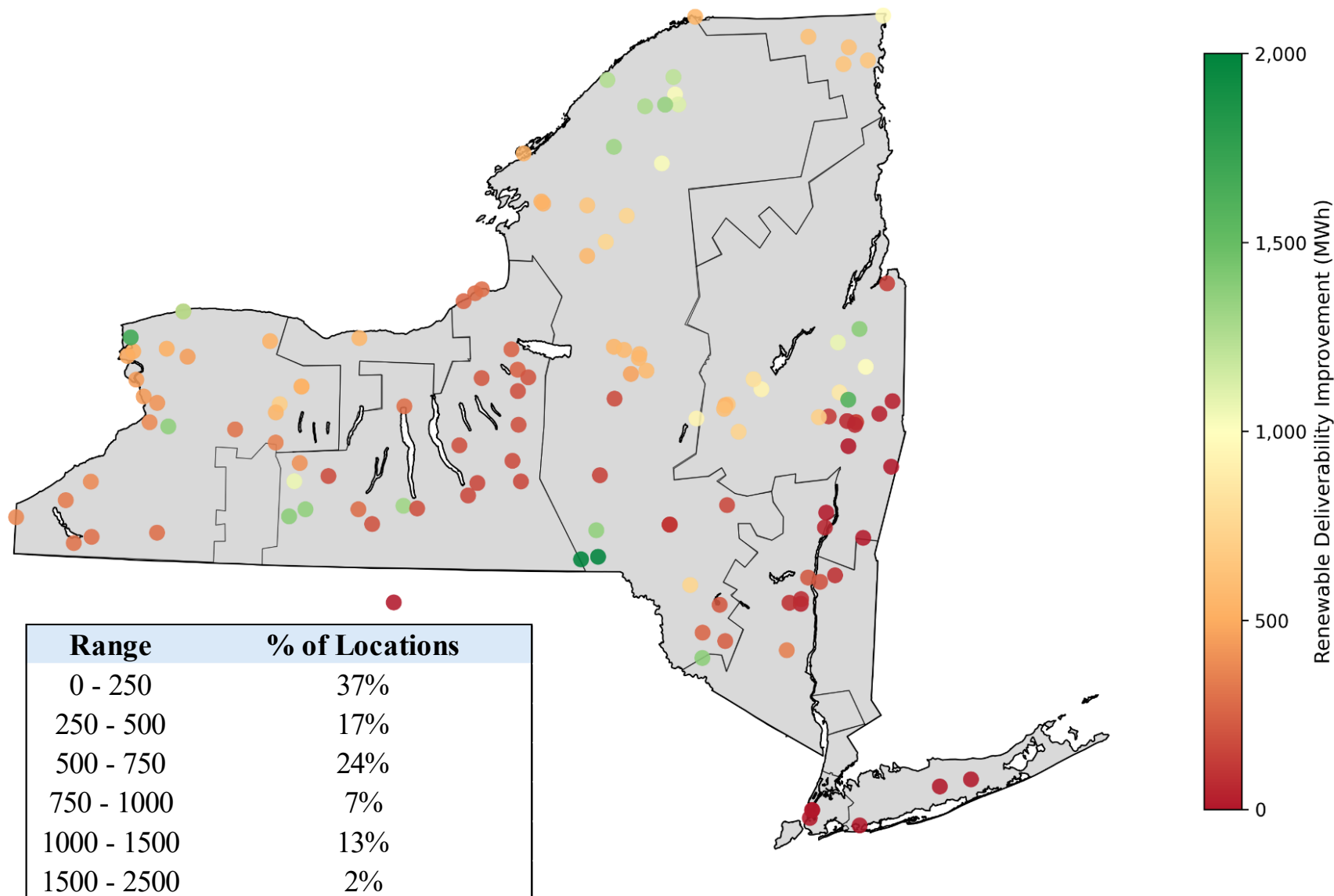
Renewable Deliverability Improvement Contract Case 2030 – 8 Hour Battery



Renewable Deliverability Improvement 100x44 High Load 2035 – 8 Hour Battery



Renewable Deliverability Improvement 95x44 Baseline Load 2035 – 8 Hour Battery



Implied Net REC Cost

Definition:

- The net cost of incremental renewable energy deliveries from an investment in generation, storage, or transmission.
- Calculated as the resource's levelized Cost of New Entry (CONE), less energy and capacity revenues, divided by the incremental renewable energy it provides:
 - For wind and solar, incremental renewable energy is the annual potential generation of an additional MW adjusted down by its Marginal Curtailment Rate
 - For energy storage, incremental renewable energy is the Renewable Deliverability Improvement (RDI) of an additional MW (e.g., the annual MWh of renewable generation it would save from being curtailed)

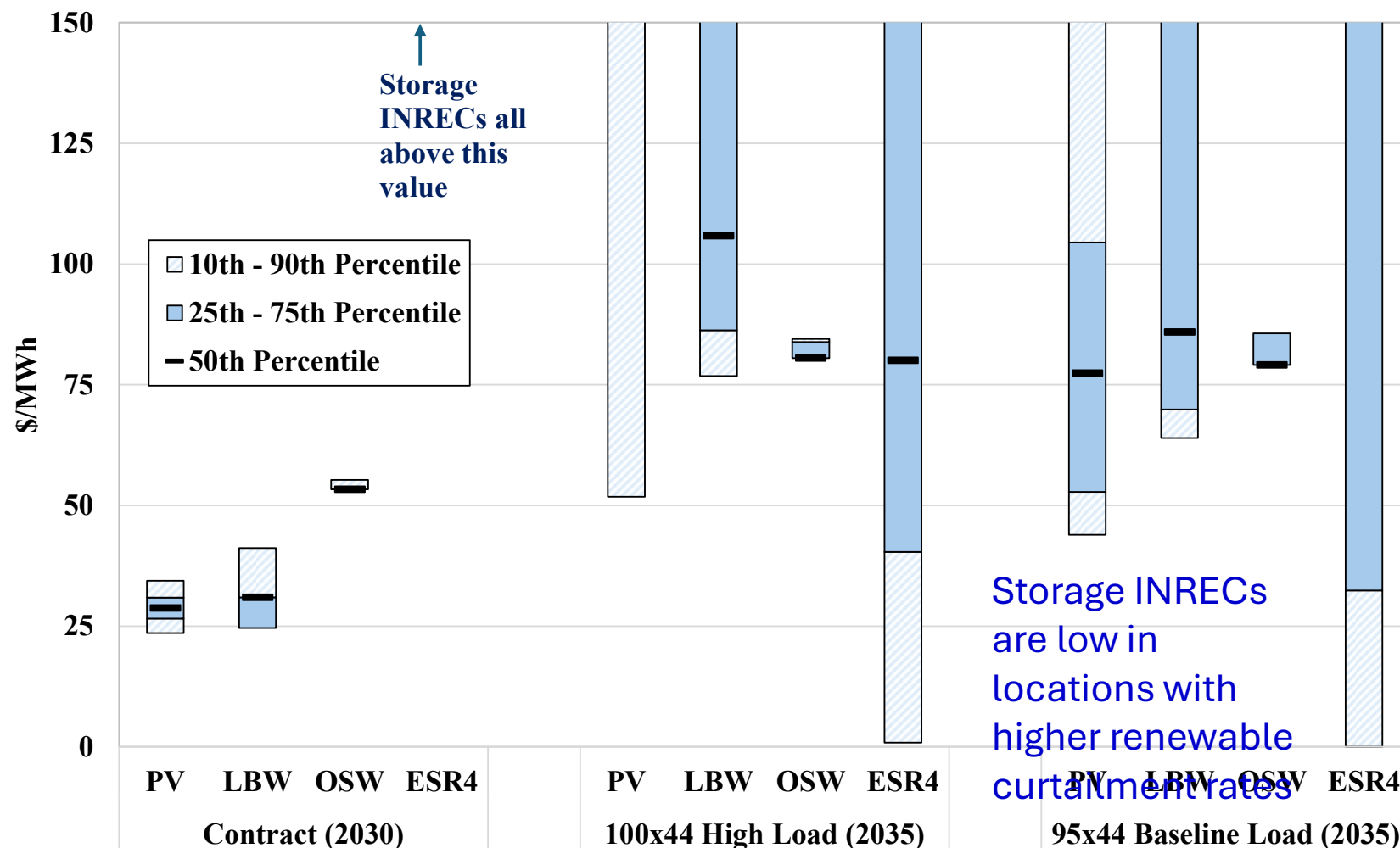
Implied Net REC Cost

- The implied NET REC cost is calculated as follows:

$$\frac{CONE(\$) - E\&AS\ Revenues(\$) - Capacity\ Revenues(\$)}{Incremental\ Deliverable\ Clean\ Energy\ (MWh)}$$

- For renewables, the Incremental Deliverable Clean Energy is the resource's annual potential output multiplied by (1 – Marginal Curtailment Rate)
- For battery storage, the Incremental Deliverable Clean Energy is equal to the Renewable Deliverability Improvement (RDI)
- CONE values are from the MMU's 2025 SOM Report, based on public sources including NYISO's DCR study and NREL Annual Technology Baseline
 - CONE values are reduced for levelized value of federal ITC/PTC in all years for storage and through 2030 for wind and solar
- Capacity prices are assumed to be set by existing unit going-forward costs in 2030. In 2035, capacity prices are set by a new GT CONE in New York City and going-forward costs in other areas
- We assume Capacity Accreditation factors based on the 2026/27 CAFs for the Contract Case and the Outlook Appendix D for the Policy Cases

Implied Net REC Costs by Technology and Case



Recommendations for Future Outlook Studies

- P23-1: Model realistic local capacity requirements driven by changes in the resource mix and transmission network;
- P24-1: Represent drivers of winter risk including fuel unavailability in capacity expansion model;
- P22-1: Model procurement of ancillary services in production cost models, considering how future needs will be driven by resource mix changes;
- P22-2: Perform an 'optimized' production cost model sensitivity case in which renewable capacity in locations with high marginal rates of curtailment is relocated to locations with lower marginal rates of curtailment;
- P19-6: Consider transmission outages and day-ahead net load forecast error when estimating production costs and curtailment.

Policy Cost Estimate Methodology

- Slide 3 shows a \$15 billion annual difference (incl. production costs and levelized investment + fixed costs) between the 100x44 and 95x44 cases
 - We compare the Baseline Load forecasts with nuclear build limitation for each case
- Production costs are derived from the PLEXOS 2044 Outlook cases
 - Production costs from the 100x44 High Load case are scaled down to reflect a Baseline load estimate
- Levelized investment costs and fixed costs are estimated from cumulative build and retirement quantities by technology and zone in the capacity expansion model, multiplied by estimated annualized CONE and GFC values. We use the following sources for GFC and CONE values:
 - Wind and solar CONE and existing unit GFCs: MMU 2025 State of the Market report
 - New CT, Hydrogen CT, and Battery Storage CONE: NYISO 2024 Demand Curve Reset
 - New nuclear CONE: EIA Annual Energy Outlook 2025